Department for
Business, Energy
& Industrial Strategy

NEP / NZT Endurance Field Well Integrity Risk Assessment

Key Knowledge Document

NS051-SS-REP-000-00011 B02

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Acknowledgements

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1 Scope

As part of the Northern Endurance Partnership project (NEP), the Endurance field in the Southern North Sea is planned to be used for long-term geological storage of CO_2. The field is a four-way dip-closure within the Bunter sandstone formation of the Southern North Sea. It is an undepleted saline aquifer, approximately 22km long, 7km wide and over 200m thick where three wells have already been drilled and permanently abandoned through the store itself, with others off-structure in the surrounding regional aquifer. The project plans to drill new dedicated injection wells for CO_2 disposal.

This technical note has been developed to evaluate the abandonment of the existing legacy wells and the likelihood of leakage of CO_2 and subsequent breach to seabed (or other neighbouring formations). This document will eventually form part of a store permit application to the UK regulator and will be publicly available.

In addition, an evaluation of the risk of leakage of brine from off-structure wells has been made, due to the long-term transient pressurisation of the Bunter sandstone regional aquifer from brine displaced from the Endurance structure by CO2.

Note: This assessment was generated based primarily on well status data available at the time of writing, and therefore may have some inherent uncertainties.

2 References

SPE Papers referenced are listed below:

- SPE 131336 Investigations on Casing-Cement Interaction with Application to Gas and CO_2 Storage Wells
- SPE 126226 Effective Zonal Isolation in CO_2 Sequestration Wells
- SPE 132442 A critical Assessment of CO_2 Injection Strategies in Saline Aquifers
- SPE 125839 Well Integrity and Regulatory Considerations for CO_2 Injection Wells
- SPE 136160 CO_2 Sequestration Wells – the Lifetime Integrity Challenge
- OTC 20724 CO_2 Injection and Storage – Qualification of Well Barriers and Adjacent wells
- SPE/IADC 119267 Improving Wellbore Seal Integrity in CO_2 Injection Wells
- White Rose Project Key Knowledge Deliverables K38 and K42

Other references cited in the footnotes on the relevant page

3 Symbols and Abbreviations

For the purpose of this document, the following symbols and abbreviations apply:

AOI	Area of Interest
BWOC	By Weight of Cement
BBL	Barrels
BML	Below Mud Line
°C	Degrees Celsius
CaCl2	Calcium Chloride
CBL	Cement Bond Log
CGP	Clean Gas Project
CO_2	Carbon Dioxide
CSG	Casing
cu. ft.	cubic feet
DPZ	Distinct Permeable Zone
EOWR	End of Well Report
FG	Fracture Gradient
ft	Feet
GP	BP Group Practice
gpm	gallons per minute
GVI	General Visual Inspection
ID	Internal Diameter
km	kilometres
Klbs	Thousand Pounds
lb/ft	Pounds Per Foot
LOT	Leak Off Test
m	meters
MC or m3	Meters Cubed
MD	Measure Depth
MSL	Mean Sea Level
MT	Metric Tonnes
NaCl	Sodium Chloride
NEP	Northern Endurance Partnership
NZT	Net Zero Teesside
P&A	Plug & Abandonment
ppf	pounds per foot
PPFG	Pore Pressure Fracture Gradient Profile
ppg	pounds per gallon

psi	pounds per square inch
QRA	Quantitative Risk Assessment
ROV	Remotely Operated Vehicle
RTE	Rotary Table Elevation
RKB	Rotary Kelly Bushing
sg	specific gravity
sxs	sacks
SIWHP	Shut-in Wellhead Pressure
TOC	Top of Cement
TOL	Top of Liner
TVDBRT	True Vertical Depth Below Rotary Table
TVDSS	TVDSS – True Vertical Depth Subsea
WD	Water Depth
# (hash sign)	Pounds Per Foot

Table 1 Glossary

4 Executive Summary

The Endurance field is one of the largest saline aquifer reservoirs suitable for CO2 storage in Europe. It has the advantages of no overlying permeable sands, good structural closure, an overlying impermeable salt as a cap rock and only three legacy well penetrations into the reservoir. All of these factors combine to make the Bunter sandstone in Endurance not only one of the largest, but one of the most suitable stores[1] available.

The three on-structure legacy wells drilled by Mobil in 1970, BP in 1990 and National Grid (NG) in 2013 were assessed for existing integrity, risk of CO2 leakage, quantification of the risked leak rate and potential remedial actions. A quantitative risk assessment was carried out in partnership with Risktec, a specialist provider familiar with regulatory and industry best practice in evaluating CCUS stores. The leak rates modelled in this work are considered conservative, as they do not take into account rate-dependent formation deliverability (which limits leak rate from the reservoir rock itself), and friction along the leak paths themselves.

A further leak modelling study was carried out in partnership with Heriot Watt University to address the inherent conservatism in the Risktec QRA, using a fine-grid simulator to model formation deliverability and friction. Full results of this study are not available at the time of writing.

The initial reservoir fluid in Endurance is a salt-saturated brine. Even if left un-isolated, it will not flow to the sea-bed as the reservoir is normally-pressured and the brine denser than seawater; however the injection of CO2 will raise the reservoir pressure, and additional work has been done to demonstrate that the risk of leakage through existing well barriers and isolations is low, particularly in the oldest of the three wells.

National Grid 42/25d-3 is the most recent well, drilled specifically to appraise the field for CO2 storage, and has been abandoned in line with current industry and regulatory guidelines with a combination (2-barrier) cement isolation of the Bunter sand.

BP 42/25-1 and Mobil 43/21-1 were abandoned in line with regulatory and industry guidance at the time, but records of verification of barrier integrity were less detailed than required today. The primary barriers in both wells is a cement plug set above the Bunter sand, sufficient to withstand the maximum anticipated CO2 pressure at cessation of injection. The secondary barriers in both wells have been set at a shallower depth where the formation may not withstand the increase in reservoir pressure, and so cannot be counted as formal barriers. In mitigation, the overlying Rot Halite salt layer is predicted to “creep” over time (i.e. close in and form a seal) above the primary barriers and provide additional confidence in CO2 isolation, effectively re-instating the natural cap rock. This will already have occurred in the time since 43/21-1 was abandoned, and will have occurred in 42/25-1 5 to 10 years after injection commences.

In the remote chance that CO2 does leak from a legacy well, A specialist study was commissioned to do a high level evaluation of the potential to re-enter and remediate. These operations are complex and costly, but are within industry experience – similar operations have been done to regain access to wells after hurricane damage to platforms in the Gulf of Mexico, for example. A high level review is included in this document in Section 11, and a detailed evaluation will be submitted in the Corrective Measures Plan as part of the store permit application in due course.

Raising the pressure within the Endurance field has an influence on the pressure in the regional aquifer; injection of CO2 displaces brine out of the structure into the surrounding aquifer, which increases the pressure in the Bunter sand within a vicinity of the store. As there are several wells that penetrate the Bunter on their way to deeper gas-bearing horizons below, relevant wells were

[1] “Store” is used interchangeably with “Reservoir” in CCUS.

assessed for integrity and their ability to leak brine to the seabed. CO_2 leakage from off-structure wells is not possible unless the store-is over-filled and CO_2 migrates under the spill-point. The store in turn will not be overfilled, as a suitable stand-off margin between the CO_2 plume and the spill point will be maintained as a safe operating limit and monitored regularly as part of the MMV plan.

Following evaluation of potential leak paths through these off-structure wells, the likelihood of brine leakage remains low. The probability and risked leak rates from these wells will form part of the Environmental Impact Assessment to be agreed with Regulators.

All of this well integrity and risk assessment work has been extensively reviewed by NEP partners, the NSTA and external advisors appointed by the NSTA (DNV and Quintessa).

5 Project Overview

Six subsea wells will be drilled as part of the phase 1 development, transporting CO2 through a dedicated pipeline offshore for permanent underground storage in the Endurance field located in blocks 42/25 and 43/21. Simplistically, NZT comprises onshore emitters of CO2, and NEP comprises the onshore gathering network and offshore scope which also takes CO2 from the Zero Carbon Humber (ZCH) development on Humberside. A jack-up rig will be used to drill six new wells 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.

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.

A number of brine production wells may be required in future phases to bleed off the in-situ brine to maintain reservoir pressure within cap-rock limits, but are not required for phase 1.

The storage complex comprises the storage site, its Triassic underburden to the base of the Zechstein Halite and the overburden up to the top Jurassic Lias. Performance of the storage site under CO_2 injection will be monitored during the injection period under a comprehensive Measurement, Monitoring and Verification Plan (MMV Plan). After injection ceases, the storage site and storage complex will be monitored for a number of years after the wells are decommissioned, before responsibility for the storage complex is transferred to the designated Competent Authority.

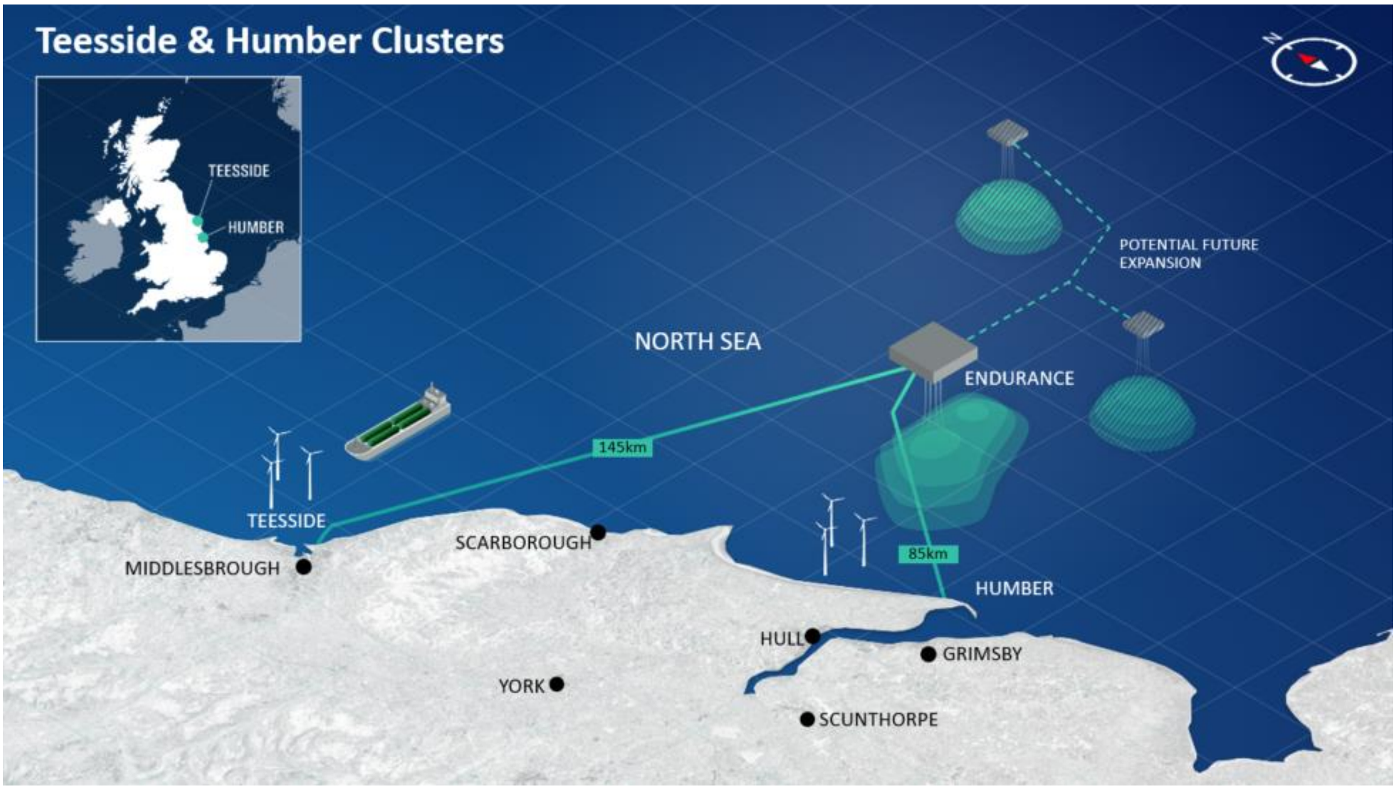


Figure 1 NEP Phase 1 Development

Drilling will start in 2025 with all wells drilled before first CO2 injection in 2026.

Target CO_2 injection rate is 1 million tonnes per annum (MTPA ~52MMSCF/D at standard temperature and pressure, equivalent to 19,000 bbl liquid per day approximately) per well average, with up to 1.5 MTPA peak.

This technical note focusses on both the on and off-structure legacy well integrity status, two different studies incorporating probabilistic semi-quantitative risk assessment to evaluate the potential for leakage, and a high level view of remediation operations should that be required.

6 Wells Within Storage Complex

Figure 2 shows the Top Bunter depth structure map over the Endurance storage site showing license block boundaries (broken black line) as well as exploration and appraisal wells within the Area of Interest (AOI).

42/25d-3, 42/25-1, and 43/21-1 are the only wells to have penetrated Endurance. 43/21-1 initially appraised the structure in an unsuccessful attempt to discover hydrocarbons. The 42/25-1 well was later drilled by BP as part of a license obligation, followed by the 42/25d-3 well drilled by National Grid for carbon capture appraisal purposes. Although off-structure, the 43/21-2 and 43-21/3 wells have been included for assessment as they are within the license block boundary and are also considered to be within the storage complex.

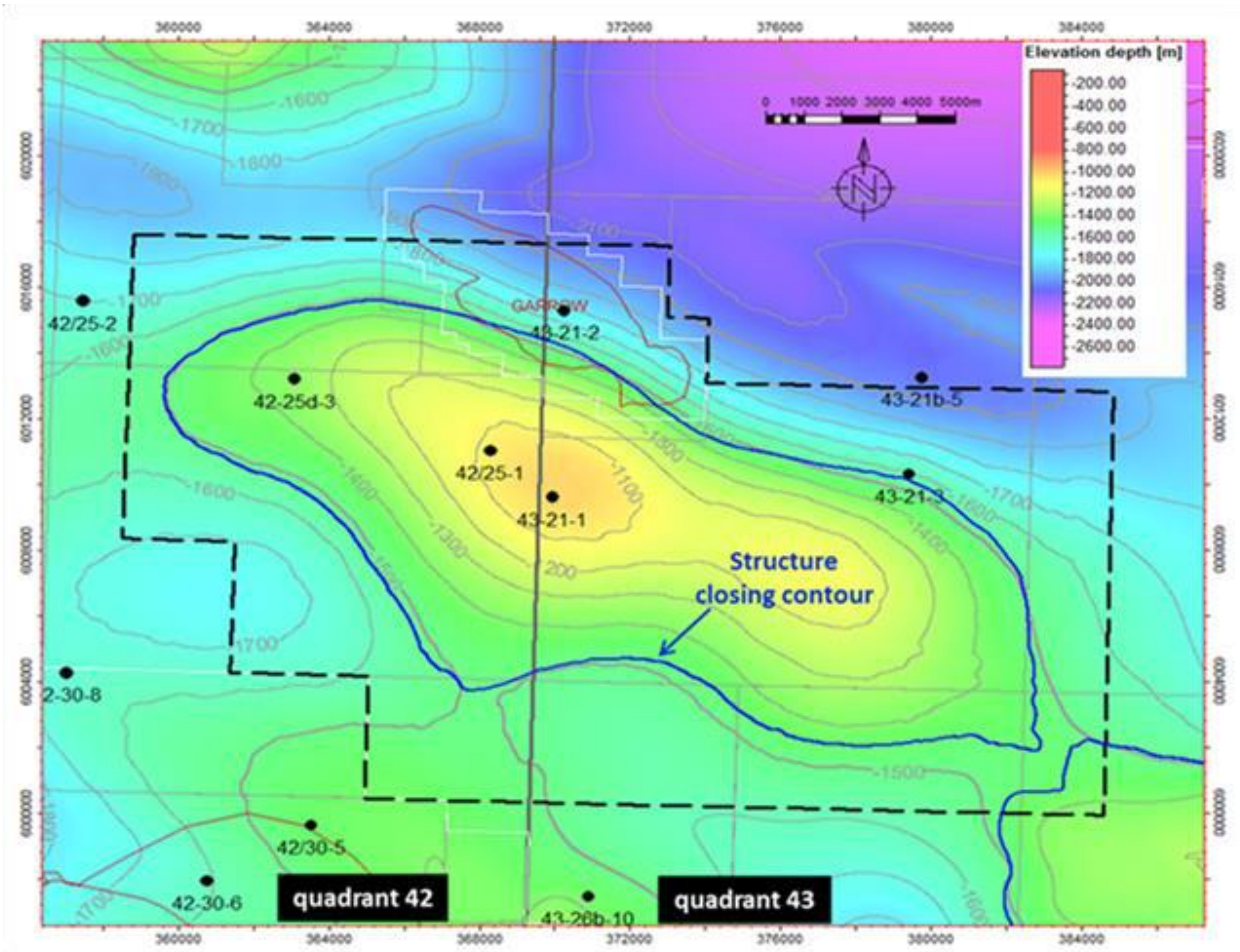
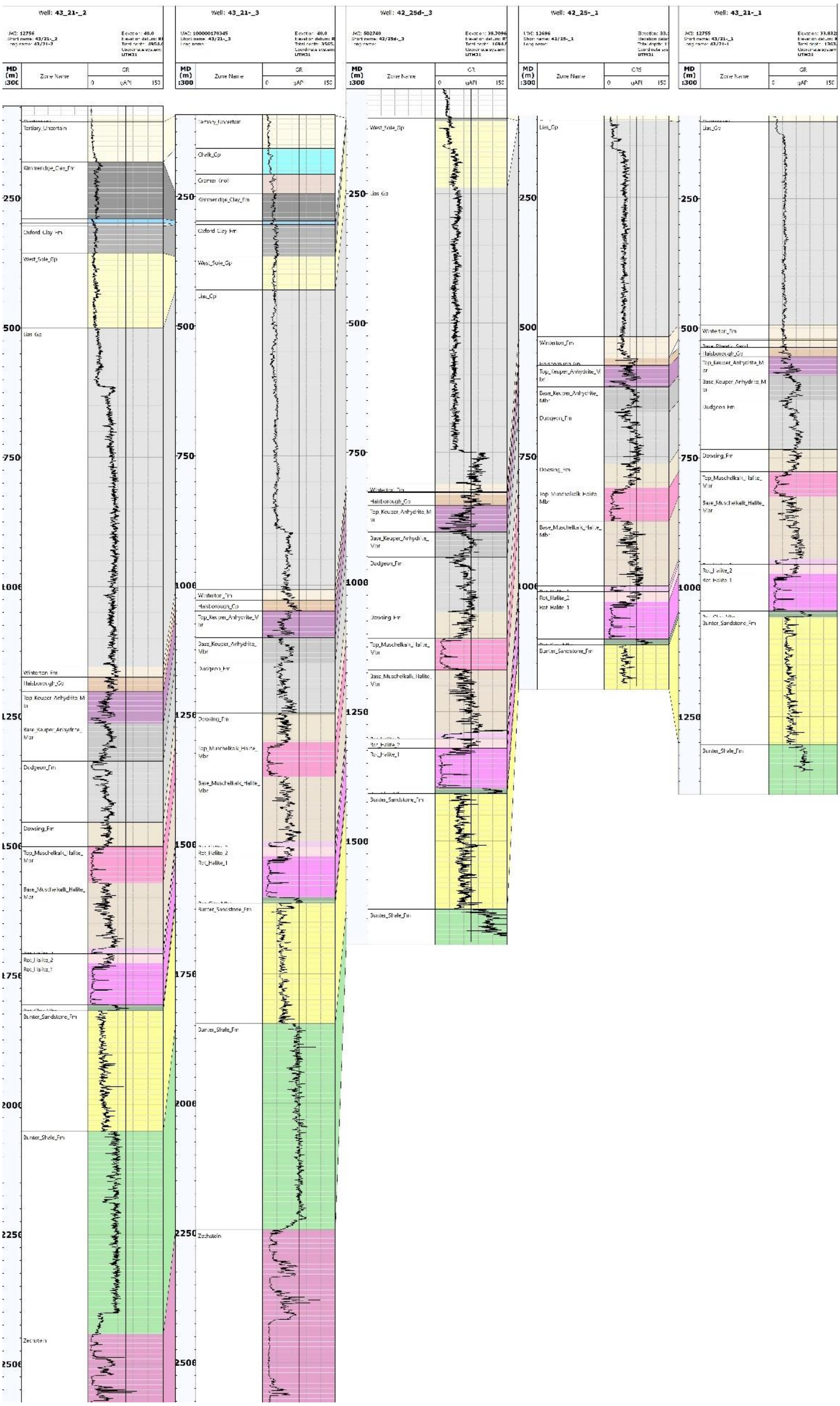


Figure 2 Exploration and Appraisal Wells in and Around Endurance

Figure 3 shows the main stratigraphy for the Endurance area with the characteristics of the individual formations, key features being the injection reservoir in the Bunter sand (shaded yellow).



Note that 43/21-2 and 41/21-3 TD pre-Zechstein but not shown here for scaling clarity

Figure 3 Endurance Area Lithology

It should be noted that there are no other overlying Discrete Permeable Zones (DPZs) on structure. As such, only the Bunter sand needs to be considered for abandonment and well integrity assessment purposes.

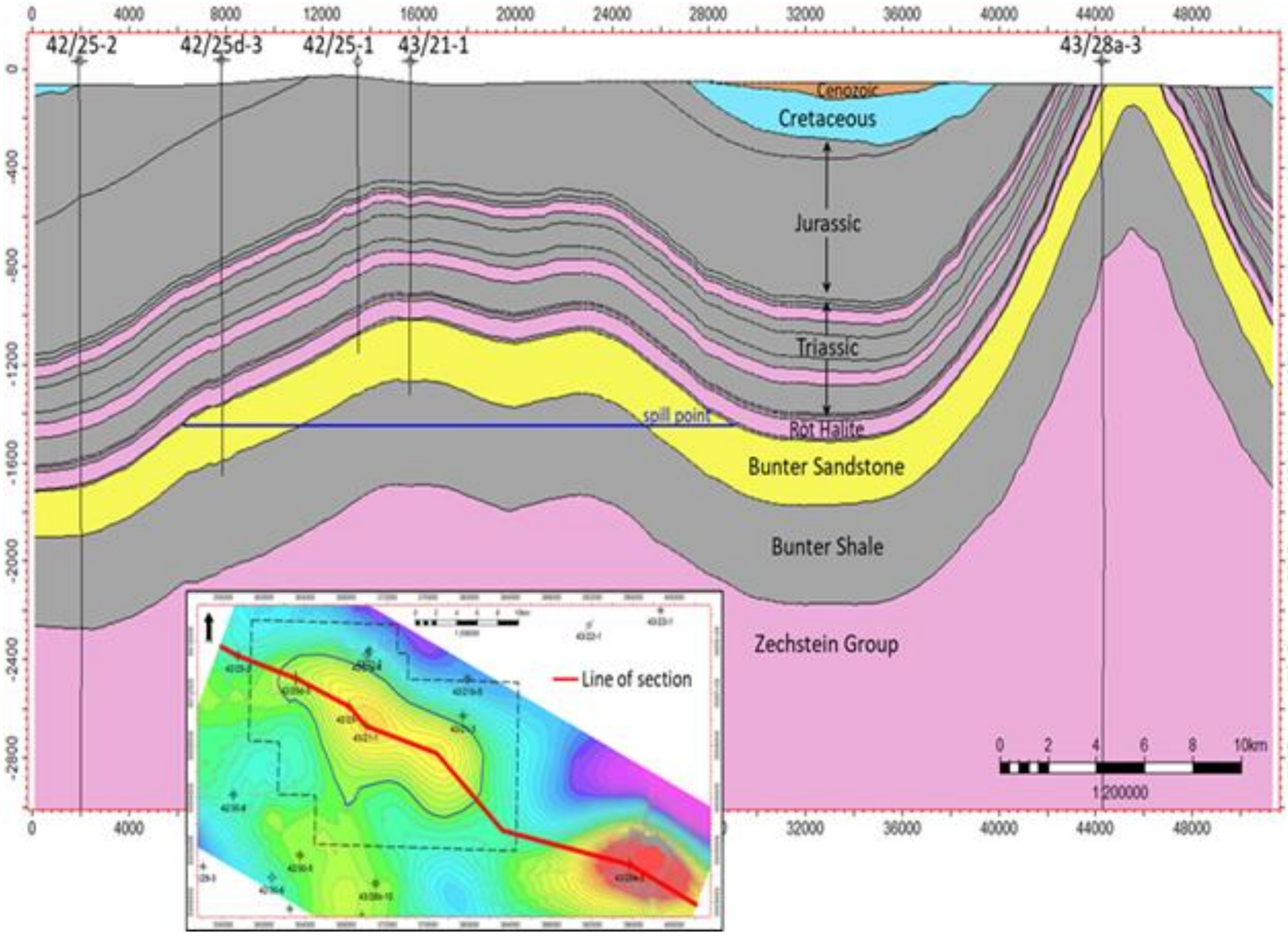


Figure 4 WNW-ESE Cross-Section Through the Endurance Structure and Salt Diapir to SE

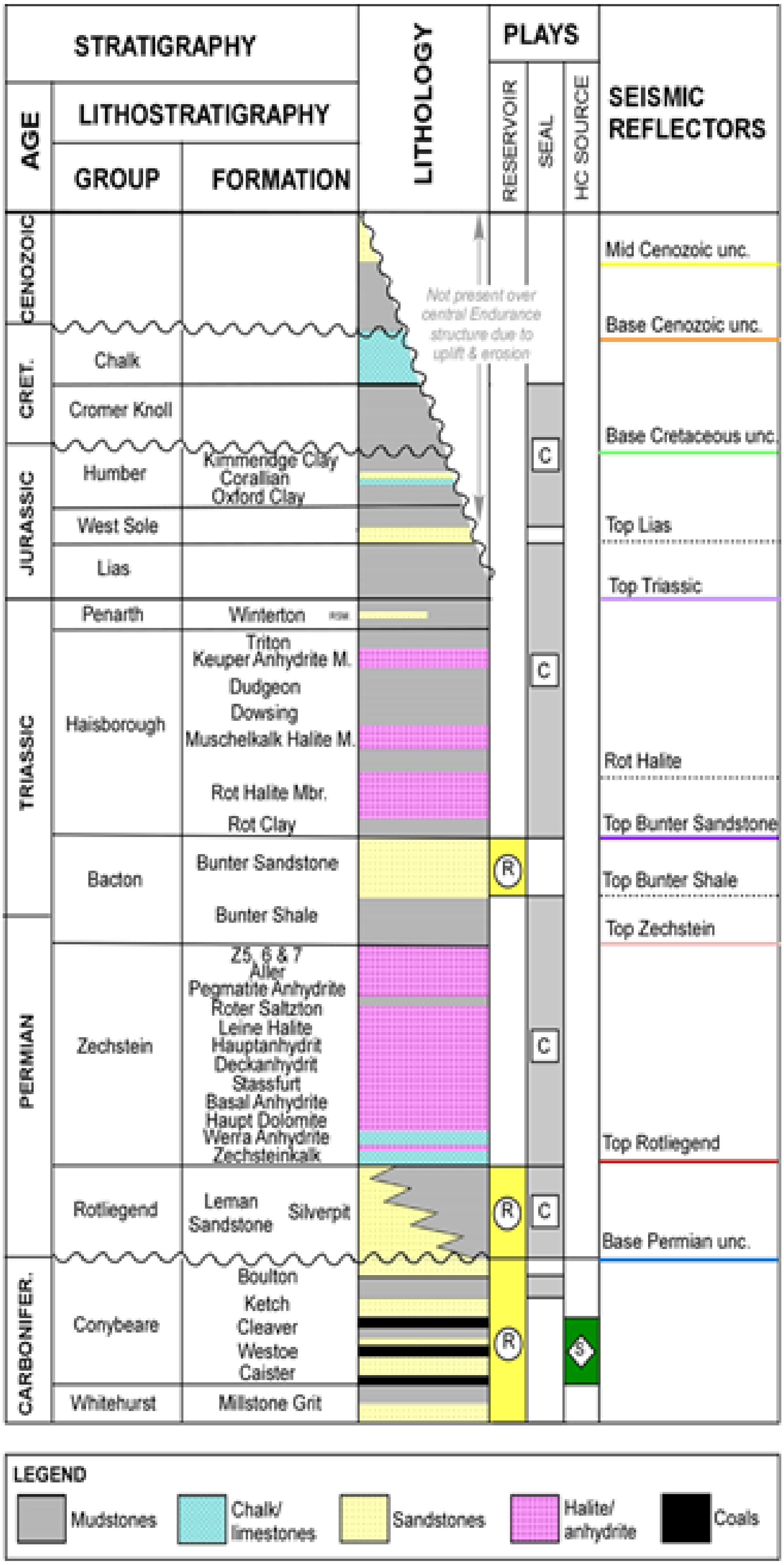


Figure 5 Lithostratigraphy of the Endurance Area

6.1 Potential Leak Mechanisms from Offset Abandoned Wells

6.1.1 Current Status

All five wells (three on-structure, 2 off-structure but within the complex) have been permanently abandoned with their wellheads removed and casing cut below mudline, and abandonment details lodged with the UK North Sea Transiiton Authority.

In their current state and with no CO2 injection, the risk of leakage from the Bunter is zero; the Bunter brine has a gradient of ~0.51 psi/ft at the 42/25-d3 well and is normally pressured via an outcrop[2] at the sea bed adjacent to Endurance, so cannot flow to the seabed. There are no other overlying permeable zones.

The two off-structure wells TD below the Bunter in the carboniferous; 43/21-2 encountered hydrocarbons and was plugged back across the entire open hole, with two further plugs above this and below the Bunter. A DST was run on 43/21-3 but the well did not flow and the carboniferous abandoned behind a cemented liner and two further plugs below the Bunter.

6.1.2 After Commencement of CO_2 Injection

The potential for one of the offset abandoned wells to provide a leak mechanism for CO2 from the store depends on:

- Whether CO_2 would be present at, or could migrate to the well location
- Whether the current abandonment condition of the well provides adequate effective barriers to prevent leakage of CO_2 outside the complex
- Whether any leakage into shallower formations that might occur could be detected and, if necessary remediated within the injection and subsequent monitoring period

Section 7 provides a summary of the analysis of these first two factors for the offset abandoned wells.

[2] The reverse will happen when injection commences; some brine will be expelled from the outcrop as store / reservoir pressure increases.

6.2 PPFG Information

Two PPFG data sets have been generated – one for the 42/25d-3 well on the western flank, and one for the 43/21-1 crestal exploration well specifically. These are shown in Figure 6 and Figure 7 below.

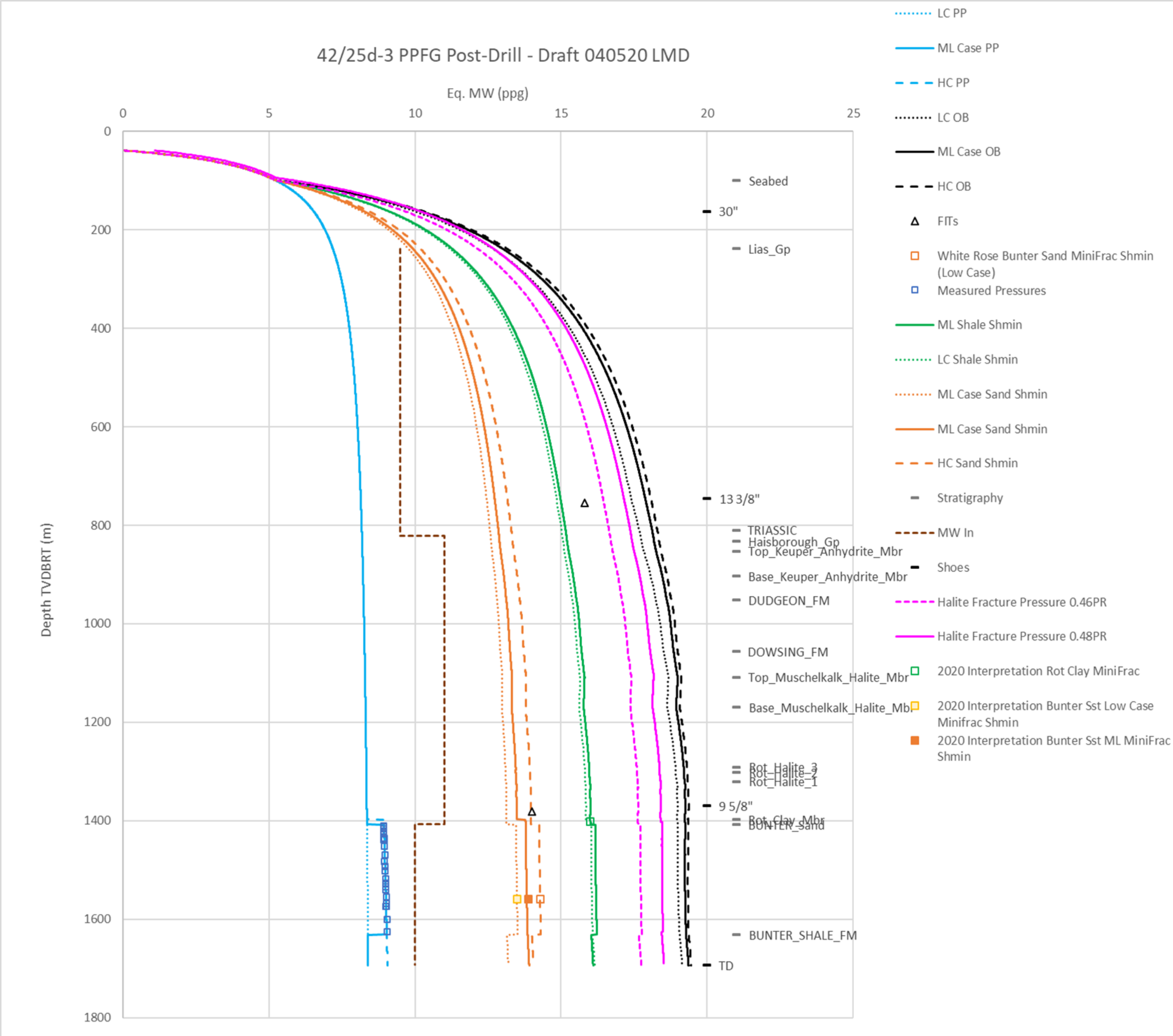


Figure 6 Field Shale Sh_{min} based on 42/25d-3 PPFG Post-Drill PPFG

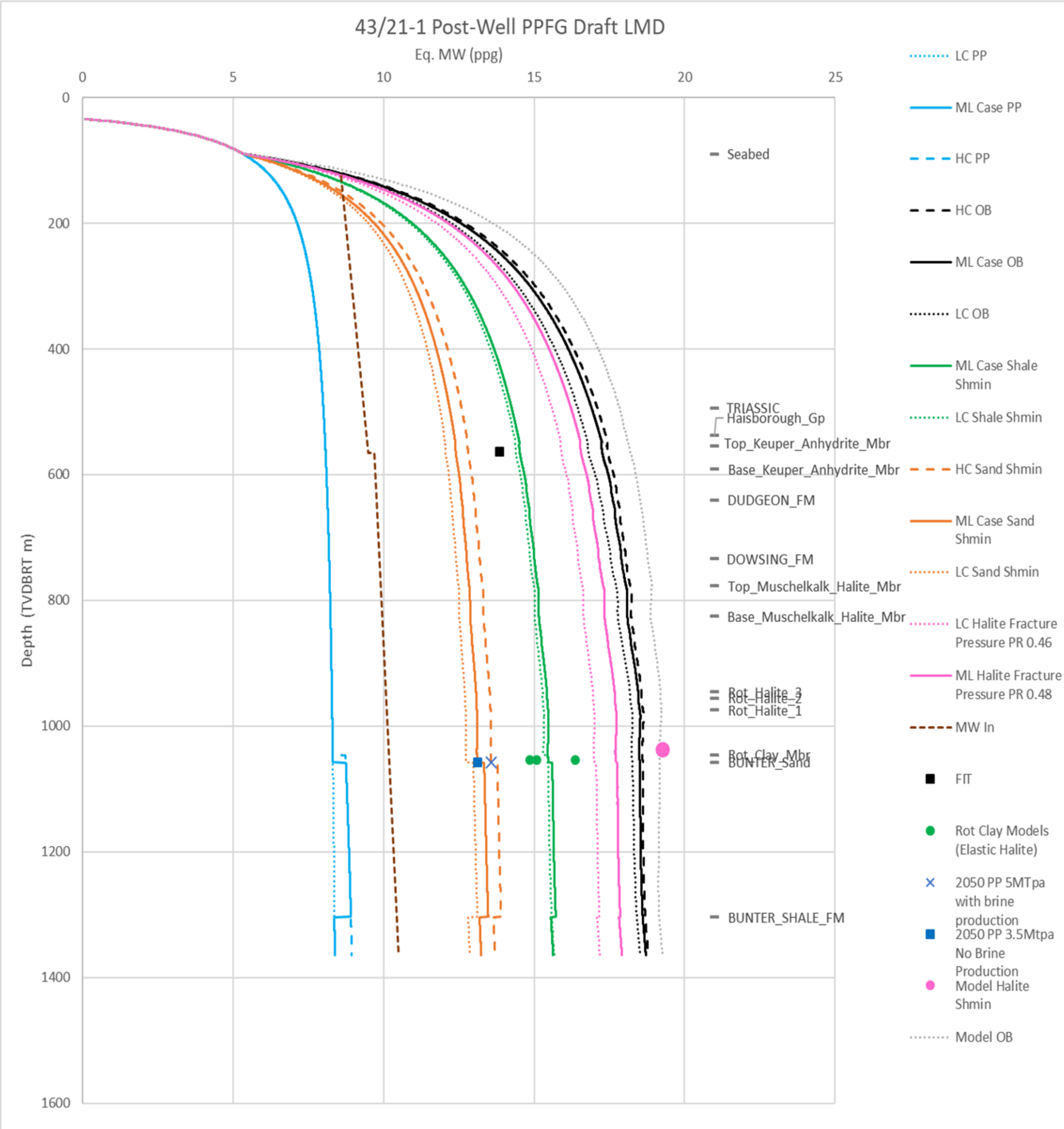


Figure 7 Field Shale Sh_{min} based on 43/21-1 Post-Well PPFG (Crestal Well)

7 Overall Assessment of Abandoned Offset Wells

Table 2 below is a consolidated summary of some of the key requirements for zonal isolation common across industry in and Offshore Energy UK (OEUK) well decommissioning guidelines. Table 2 summarises the assessment of individual well barrier conditions against these requirements.

For wells drilled prior to January 2008, BP typically expects risk assessments to be performed which this report intends to inform. All of the wells in this report were drilled pre-2008, except for the 42/25d-3 well, which was drilled by National Grid. Of the pre-2008 wells, only the 42/25-1 well was drilled by BP 30+ years ago.

a)	All permeable zones identified
b)	Two lateral barriers between the flow potential zone and surface (combination barriers can be used)
c)	Minimum of one lateral barrier between distinct flow potential zones. (BP Practice requires two barriers where the seal of the upper zone does not contain the pressure from the lower flow potential zone)
d)	Wellbore barrier with a minimum height of 100 ft (30 m), or for a combination barrier 200 ft (60 m)
e)	Annular barrier with a minimum height of 650 ft (200 m), or for a combination barrier 1,300 ft (400 m) when circumferential cement bond logging is not used
f)	The base of the lateral barrier is at a depth at which the formation fracture pressure can withstand the pressure from the flow potential zone
g)	Annular barrier is verified by volumetric / lift pressure method or cement bond log method. For verification with a circumferential cement bond log, 100 ft (30 m) is required
h)	Wellbore barrier is verified by tagging / pressure testing / inflow testing

Table 2 Requirements for Well Abandonment

	43/21-2	43/21-3	42/25d-3	42/25-1	43/21-1
Well located on the Endurance structure	No	No	Yes	Yes	Yes
Permeable zones identified	Bunter formation only[1]	Bunter formation only[1]	Bunter formation only[1]	Bunter formation only[1]	Bunter formation only[1]
Top Bunter formation MD	5963 ft	5295ft	4617 ft	3659 ft	3468 ft
Primary Annular Barrier MD[5]	308 -984 ft (676 ft)	Unknown	2904- 4617 ft (1713 ft)	Not applicable (OH)	Not applicable (OH)
Primary Wellbore Barrier MD[5]	364 – 984 ft (620 ft)	394 – 1,050 ft (656 ft)	3864-4617 ft (753 ft)	3429 – 3659 ft (230 ft)	3300 - 3468 ft (168 ft)
Secondary Annular Barrier MD[5]	5906 -5963 ft (57 ft)	Unknown	2904- 4617 ft (1713 ft) combination barrier	381 – 1828 ft (1447 ft)	305 -1855 ft (1550 ft)

	43/21-2	43/21-3	42/25d-3	42/25-1	43/21-1
Secondary Wellbore Barrier MD[5]	None	None	3864-4617 ft (753 ft) combination barrier	1667 – 1991 ft (324 ft)	1516-1962 ft (446 ft)
Verification of Primary Annular Barrier	Unknown	Unknown	Unknown	Unknown	Unknown
Verification of Primary Wellbore Barrier	Unknown	Unknown	Tag & Pressure Test. No inflow test	Unknown	Unknown
Verification of Secondary Annular Barrier	CBL	Unknown	Unknown	Unknown	Unknown
Verification of Secondary Wellbore Barrier	None	None	Tag & Pressure Test. No inflow test	Unknown	Tag only. No pressure test. No inflow test
Lateral Barrier Overall Summary.[3, 6]	Primary Barrier (12.37 ppg FG): Cannot withstand proposed maximum reservoir pressure. No Secondary Barrier. Note: Prior injection pressure in the Bunter reservoir (2,201 psi @ 4,610 ft TVD ss) exceeds formation fracture pressure at the base of the primary barrier.	Primary Barrier (12.62 ppg FG): Cannot withstand proposed maximum reservoir pressure. No Secondary Barrier. Note: Prior injection pressure in the Bunter reservoir (2,201 psi @ 4,610 ft TVD ss) exceeds formation fracture pressure at the base of the primary barrier.	Primary Barrier (16.00 ppg FG): Is able to withstand proposed maximum reservoir pressure. Secondary Barrier (15.99 ppg FG): Is able to withstand proposed maximum reservoir pressure	Primary Barrier (15.82 ppg FG): Is able to withstand proposed maximum reservoir pressure. Secondary Barrier (14.60 ppg FG): Secondary barrier base is only able to withstand a maximum of 2,200 psi @ 4,610 ft TVD ss in the Bunter Reservoir.	Primary Barrier (15.72 ppg FG): Is able to withstand proposed maximum reservoir pressure. Secondary Barrier (14.56 ppg FG): Secondary barrier base is only able to withstand a maximum of 2,200 psi @ 4,610 ft TVD ss in the Bunter Reservoir.
Assessment versus guidelines[4]	b) Only one lateral barrier	b) Assumed lateral barrier,	g) No documentation	f) A Bunter formation	f) A Bunter formation

	43/21-2	43/21-3	42/25d-3	42/25-1	43/21-1
	f) The Bunter formation pressure can break the rock at the base of the primary barrier g) No documentation of annular barrier verification h) No documentation of wellbore barrier verification	but no data available to confirm presence e) No information on annular barrier TOC f) The Bunter formation pressure can break the rock at the base of the primary barrier g) No documentation of annular barrier verification h) No documentation of wellbore barrier verification	of annular barrier verification h) Wellbore barrier verified by tagging and pressure testing but no inflow testing	pressure of 2,900 psi can break the rock at the base of the secondary barrier g) No documentation of annular barrier verification h) No documentation of wellbore barrier verification	pressure of 2,900 psi can break the rock at the base of the secondary barrier g) No documentation of annular barrier verification h) No documentation of wellbore barrier verification

Table 3 Well Abandonment Assessment Summary

[1] There are no other overlying permeable formations, perhaps only a few silt stringers.

[2] Reference Removed

[3] Assumes a maximum Bunter formation pressure of 2,900 psi @ 4,610 ft TVD ss, a variable CO_2 density gradient calculated based on pressure and temperature and shale frac gradient as per Figure 6 and Figure 7.

[4] As per Table 2

[5] These areas of cement have been inferred as primary and secondary “barriers” based on where they are situated with respect to most likely flow paths, but are not necessarily fully qualified as primary or secondary barriers. The individual well assessments provide further details on their qualification.

[6] For more information, refer to individual well assessments in this document showing CO_2 initial and final injection pressure versus shale fracture pressure. Please note that an analysis on methods to achieve maximum anticipated injection pressures in relation to cap rock strength has not been conducted as part of this report.

8 Individual Well Assessments

8.1 43/21-2

8.1.1 Well Data

Well Attribute	Data	
Surface Location	European Datum 1950: Latitude 54° 16′ 04.43″ N Longitude 0° 00′ 28.08″ E	
Operator	AGIP UK Limited (35%)	
Drilling Unit	Sedco Forex – Trident X	
Spudded	15 September 1991	
Abandoned	11 February 1992	
Duration (Well Construction)	148 days 21 hours 54 min	
Formation Pressure	1.28sg at 4950m	
Total Depth	4973m MD RTE	
Water Depth	51.25m (Lowest Astronomical Tide)	
Derrick Floor Elevation	39.35m	
Maximum Inclination	35.5° at 4846m MD	
Casing Details		**Weight – Grade – Threads**
30″ Conductor	165m	309ppf – X-52 – Vetco Gray RL4
20″ Casing	613m	133ppf – X-56 – Vetco Gray RL4S
13 3/8″ Casing	2436m	68ppf – L80 – BTC
9 5/8″ Casing	2867m	53.5 / 47ppf – N80 – NEW VAM
7″ Liner	3903m	35 / 32ppf – N80/L80 – NEW VAM
Cement Details		
30″ Cement Job	Class G 46 MC @ 1.90 sg	Returns to seabed checked with ROV. No centralizers
20″ Cement Job		
Lead	Class G 109 MC @ 1.58 sg Bentonite 2% pre-hydrated in seawater	Cement returns noted. Annulus flushed out with tubing post job.
Tail	Class G 29.7 MC @ 1.92 sg	Centralizers: ST45 CI 613m – 588m Rigid CI 82m – 22m
Final Differential Pressure		
Pressure Test		
13 3/8″ Cement Job		

Well Attribute	Data	
Lead	Class G 112.6 MC @ 1.58 sg	No losses during job. Plug not bumped, no back flow. Centralizers: ST III 2CI 2436m – 2384m ST III C3 2384m – 628m Rigid 628m – 430m
Tail	Class G 10.6 MC @ 1.92 sg	
Final Differential Pressure		
Pressure Test		
9 5/8" Cement Job		
Lead	Class G (NaCl 15% BWOC) 24.6 MC @ 1.92 sg	No losses during job. Plug bumped. Centralizers: ST III 2CI 2865m – 2837m ST III C3 2837m – 2226m
Tail	N/A	
Final Differential Pressure		
Pressure Test		
7" Cement Job		
Lead	Class G (35% silica flour) 21.8 MC @ 1.92sg	Losses of 75bbl during job, possible losses after plug bumped. Centralizers: ST IV 2CI 3905m – 3880m ST III C3 3880m – 3553m ST IV CI 3553m – 3360m ST IV C2 3360m – 2738m
Tail	N/A	
Final Differential Pressure		
Pressure Test		
Abandonment		
Plugs 1-6	Class G 3705m – 4973m	Tagged and dressed plug with 20Klbs. Tested casing to 3500psi
Plug 7	Class G 23bbl / 6 MT @ 16ppg 3000m – 3200m	No data available
Plug 8	Class G 37bbl / 9 MT @ 16ppg 2600m – 2800m	Load test to 15 tonnes
Plug 9	Class G 107bbl / 23 MT @ 16ppg 111m – 300m	Load test to 15 tonnes

Table 4 Well 43/21-2 Data

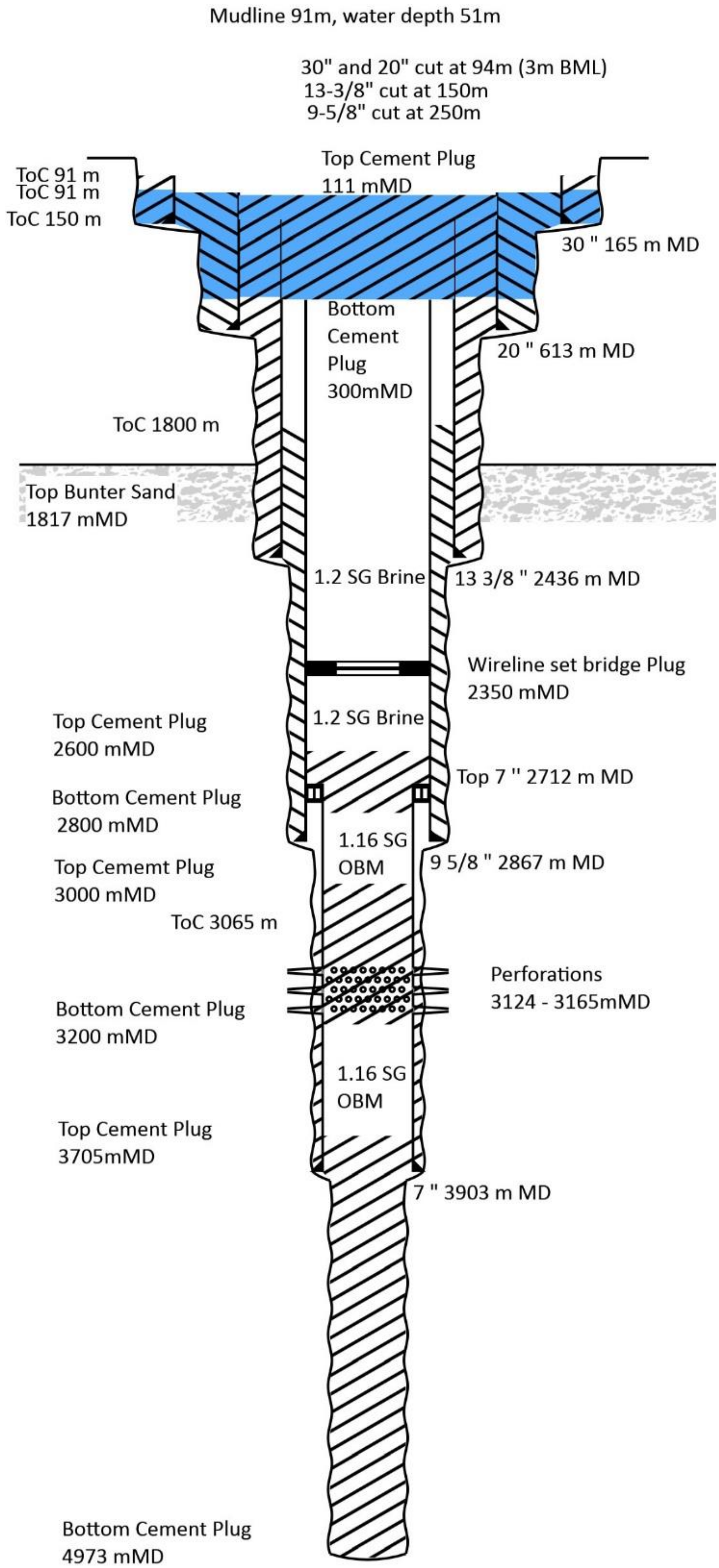


Figure 8 Well 43/21-2 Abandonment Schematic

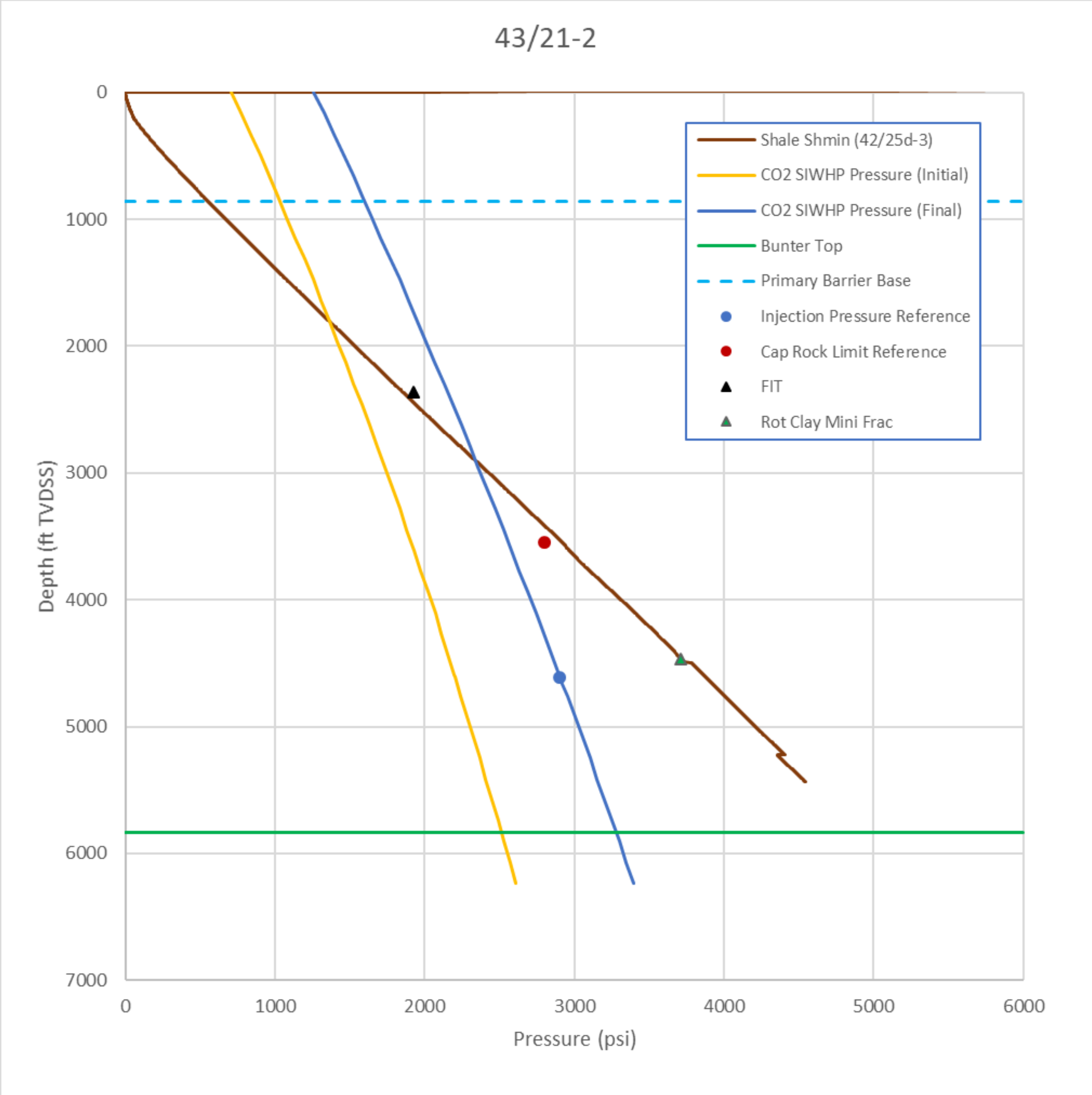


Figure 9 Well 43/21-2 CO_2 Initial and Final Injection Pressure vs. Shale S_{hmin} Pressure

8.1.2 Abandonment Assessment

This well was abandoned by a total of 9 cement plugs and one bridge plug. Furthermore, all casing strings were cut below the mudline. Although the Bunter formation (CO_2 injection reservoir) is present in this well, it is outside of the structure closing contour and therefore there is no primary entry point of CO_2. All casing strings are made of carbon steel and the cement used was standard "Class G".

Wellbore Zonal Isolation:

- Plugs #1-6: The open hole section of this well was abandoned via 6 consecutive cement plugs from well TD (4973m) to 3705m, which were subsequently tagged, dressed off and weight tested to 20Klbs. The wellbore was subsequently pressure tested to 3500psi.
- Plug #7: A 200m cement plug was then set across the perforations inside 7" liner (3200m – 3000m) using 2 7/8" tubing. This plug was set without any kind of bottom support (bridge plug, viscous pill) and was not tagged.
- Plug #8: A further 200m plug was set across the 7" liner x 9-5/8" casing overlap (2800m – 2600m) and was tagged, dressed off and weight tested to 10T with an 8 ½" bit. However, there is no evidence that the plug was set on any base. The well was then displaced to CaCl2 brine at 1.2 sg.
- Plug #9: A cement plug was set 20m below the mudline (300m – 111m), but there is no evidence that the plug was set on any base. It was tagged ~5m shallower than planned (planned 115m, tagged at 111m) and was dressed to 111m and weight tested to 40Klbs.
- Only Plug #9 serves as a lateral barrier above the top of Bunter formation. However, this well is outside of the structure closing contour.
- A 9 5/8" Dowell bridge plug was set at 2350m and tagged with the setting tool itself. Its purpose is unknown, but perhaps was installed to serve as an additional barrier prior to cutting and retrieving the casing.
- The 9 5/8", 13 3/8", 20 and 30" casings were all cut and retrieved at 250m, 150m, 94m and 94m respectively.

Annulus Zonal Isolation:

- Despite losses having been logged on the 7" cement job, CBL logs were run and confirmed TOC at 3065m and 1800m in the 7" and 9-5/8" annuli respectively.
- Cement returns to the sea floor were noted on both the 30" and 20" cement jobs, giving confidence that these annuli were fully cemented.
- Based on the information provided in the EOWR, there were no losses noted on the 13 3/8" cement job. The plug did not bump, but there was no back flow. No record available of where TOC cement was tagged during the shoe drill out.

8.1.3 13 3/8" CBL-VDL

A CBL-VDL log is available across the 13 3/8" casing (shoe at 2436m MD) which was cemented into the 20" shoe.

Interpretation of the CBL-VDL suggests good bond from the shoe to around 2180m MD, with generally poor bond across the remainder of the casing, but with some areas of good cement. Poor bond is indicated across the Bunter sand itself, but as the cement reports state that there were no losses during the job, and there is adequate bond at various intervals higher up, this suggests a micro-annulus is present. This is likely to provide isolation to brine flow, and in addition any flow path is expected to have been closed by the movement of the Rot Halite above the Bunter. Further details are shown in Appendix 15.2.

8.1.4 Summary

This well accessed a reservoir below the Bunter, and as such, and despite the likely micro-annulus, the Bunter is isolated by annular cement and casing and plug 9 to brine. There are uncertainties regarding the abandonment generally; however, there is no primary entry point of CO_2 into this well from the Bunter reservoir unless CO2 was injected under the spill point of the structure.

Long-term pressure transmission through brine is possible which is described later in this document.

Points of Note:

- Only one lateral barrier (plug #9), but not verified in accordance with current practices
- Maximum anticipated CO2 injection pressure exceeds fracture pressure of the rock at the base of the primary barrier
- No documentation exists for annular barrier verification
- A micro-annulus appears to be present across the Bunter (CBL), although good cement is indicated above.
- Limited documentation of wellbore barrier verification exists: Plugs #7, 8 and 9 are unsupported, with no evidence that plug #7 having been tagged. The only cement plugs that were pressure tested were plugs #1-6 as a cumulative whole

8.2 43/21-3

8.2.1 Well Data

Well Attribute	Data	
Surface Location	Latitude 54° 13' 31.45" N Longitude 01° 09' 01.52" E	
Operator	AGIP UK Limited (35%)	
Drilling Unit	Neddrill-3	
Spudded	30 May 1994	
Abandoned	20 August 1994	
Duration (including P&A)	82 days	
Formation Pressure		
Total Depth	3565m MD RTE	
Water Depth	54m	
Derrick Floor Elevation	40m	
Maximum Inclination	7° at 3460m MD	
Casing Details		**Weight – Grade – Threads**
30" Conductor	170m	309ppf
20" Casing	886m	133ppf
13 3/8" Casing	2255m	68ppf
9 5/8" Casing	2969m	53.5ppf
7" Liner	3541m	Unknown
Cement Details		
30" Cement Job	Unknown	
20" Cement Job		
Lead	Unknown	
Tail	Unknown	
Final Differential Pressure		
Pressure Test		
13 3/8" Cement Job		
Lead	Unknown	
Tail	Unknown	
Final Differential Pressure		
Pressure Test		
9 5/8" Cement Job		
Lead	Unknown	
Tail	Unknown	
Final Differential Pressure		
Pressure Test		

Well Attribute	Data	
7" Cement Job		
Lead	Unknown	
Tail	Unknown	
Final Differential Pressure		
Pressure Test		
Abandonment		
Plug 1	3350m – 3150m	Unknown
Plug 2	2850m – 2792m	Unknown
Plug 3	2792m – 2640m	Unknown
Plug 4	320m – 120m	Unknown

Table 5 Well 43/21-3 Data

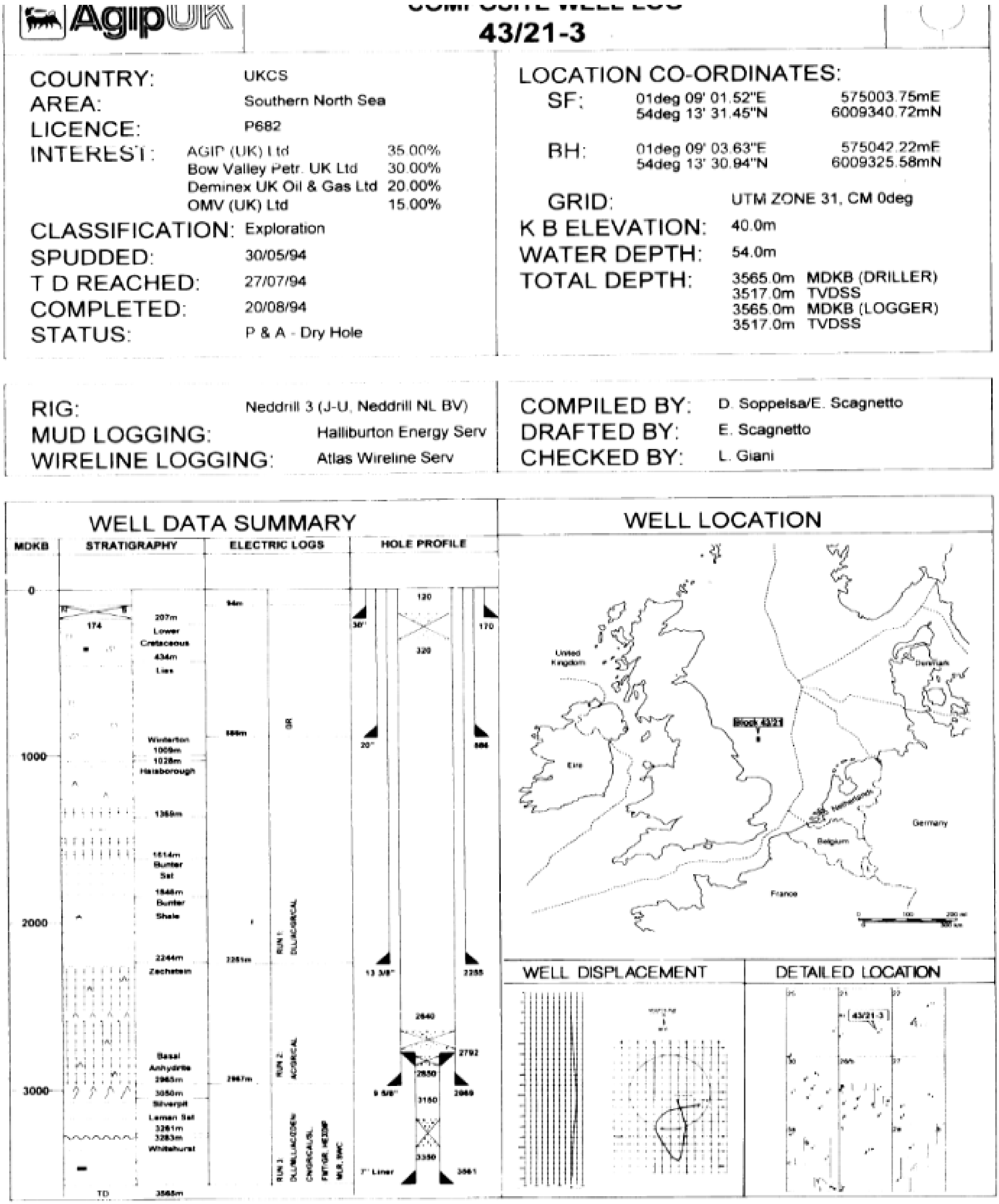


Figure 10 Well 43/21-3 Abandonment Schematic

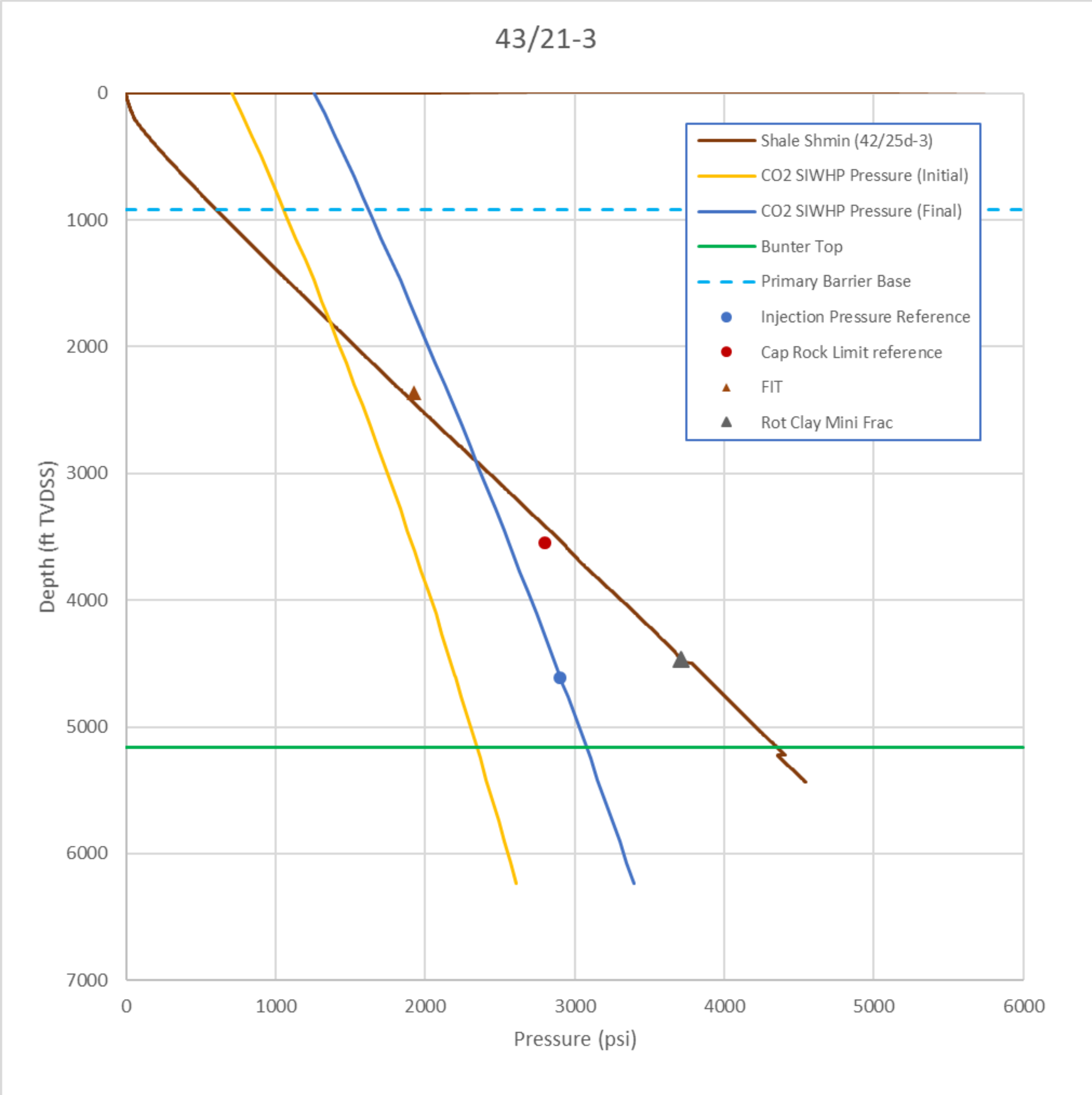


Figure 11 Well 43/21-3 CO_2 Initial and Final Injection Pressure vs. Shale S_{hmin} Pressure

8.2.2 Abandonment Assessment

This well was abandoned with a total of 4 cement plugs. Although the Bunter formation (CO_2 injection reservoir) is present in this well, it is outside of the structure closing contour and therefore there is no primary entry point of CO_2. No information was available on the type of cement used for the casing cement jobs nor the abandonment plugs, neither which verification methods were used. Although also not specified directly, it is assumed that all of casing strings were cut below the mudline.

Wellbore Zonal Isolation:

- Plugs #1-3 provide isolations from other formations but play no part in containing CO_2 from primary entry points into the well as there is no connectivity with the Bunter formation. Only plug #4 serves as a wellbore barrier above the top of Bunter formation. This cannot be confirmed as a lateral barrier as no TOC information is available for the 13 3/8" and 20" cement jobs.
- It should be noted that this well is outside of the structure closing contour.

Annulus Zonal Isolation:

- No information was available for estimated or verified TOC for any of the cement jobs.

8.2.3 Summary

This well accessed a reservoir below the Bunter, and as such, the Bunter is isolated by annular cement and casing and plug 4. There are uncertainties about the abandonment generally; however, there is no primary entry point of CO_2 into this well from the Bunter reservoir unless CO2 was injected under the spill point of the structure.

Long-term pressure transmission through brine is possible which is described later in this document.

Points of Note:

- Plug #4 acts as the only lateral barrier, which cannot be verified due to the lack of annular TOC information for the 13 3/8" and 20" cement jobs.
- No information is available on annular barrier TOC – this is relevant to the 13 3/8" cement job as it is possible that the TOC is not above the Bunter – although normal drilling practice would have been to pump the cement above the Bunter to isolate it.
- Maximum anticipated CO2 injection pressure exceeds fracture pressure of the rock at the base of the primary barrier
- No documentation of annular barrier or wellbore barrier verification
- Based on the identified potential leak paths from the Bunter formation and the well barrier elements and envelopes present, only a primary lateral barrier containment is present, but with the limited information available it is uncertain if this has been verified according to current practice.

8.3 42/25d-3

8.3.1 Well Data

Well Attribute	Data	
Surface Location	Latitude 54° 14' 50.284'' N Longitude 00° 53' 56.356'' E	
Operator	National Grid	
Drilling Unit	Energy Endeavour	
Spudded	3 June 2013	
Abandoned	27 July 2013	
Duration (Well Construction)	54.18 days	
Formation Pressure		
Total Depth	1694m MD RTE	
Water Depth	61m MSL	
Derrick Floor Elevation	39m	
Maximum Inclination	0°	
Casing Details		**Weight – Grade – Threads**
30" x 20" Conductor	163m	310lb/ft - X-52 - Leopard SD-2
13 3/8" Casing	746m	72lb/ft - L-80 - DINO VAM
9 5/8" Casing	1370m	53.5lb/ft - L-80 - VAM Top
7" Liner	1692m	29lb/ft - L80 - Vam Top
Cement Details		
30" x 20" Cement Job	Class G 331bbl @ 16ppg	Returns were observed after 271bbl slurry, a further 60bbl pumped with Well Life No evidence of centralizers
13 3/8" Cement Job		
Lead	Class G 77bbl @ 16ppg Estimated TOC @ 457m MD	Only 77bbls of planned 220bbls slurry was pumped, plug not bumped but no flow back. No evidence of centralizers
Tail	NA	
Final Differential Pressure		
Pressure Test	1,900psi for 10min	
9 5/8" Cement Job		
Lead	Class G 107bbls @ 15ppg Estimated TOC @ 885m	No plug bump observed No evidence of centralizers
Tail		
Final Differential Pressure		
Pressure Test	4,500psi for 10min	
7" Cement Job		

Well Attribute	Data	
Lead	CorrosaCem NP (Thermalock) CO_2 resistant cement 46bbls @ 15ppg Estimated TOC = TOL @ 1217m	Cement job as per plan. No evidence of centralizers
Tail	N/A	
Final Differential Pressure		
Pressure Test	4,250psi	
Abandonment		
Plug 1	Class G 1412m – 1108m (304m)	Plug set on top of packer set at 1412m. Tested plug and tagged cement at 1108m

Table 6 Well 42/25d-3 Data

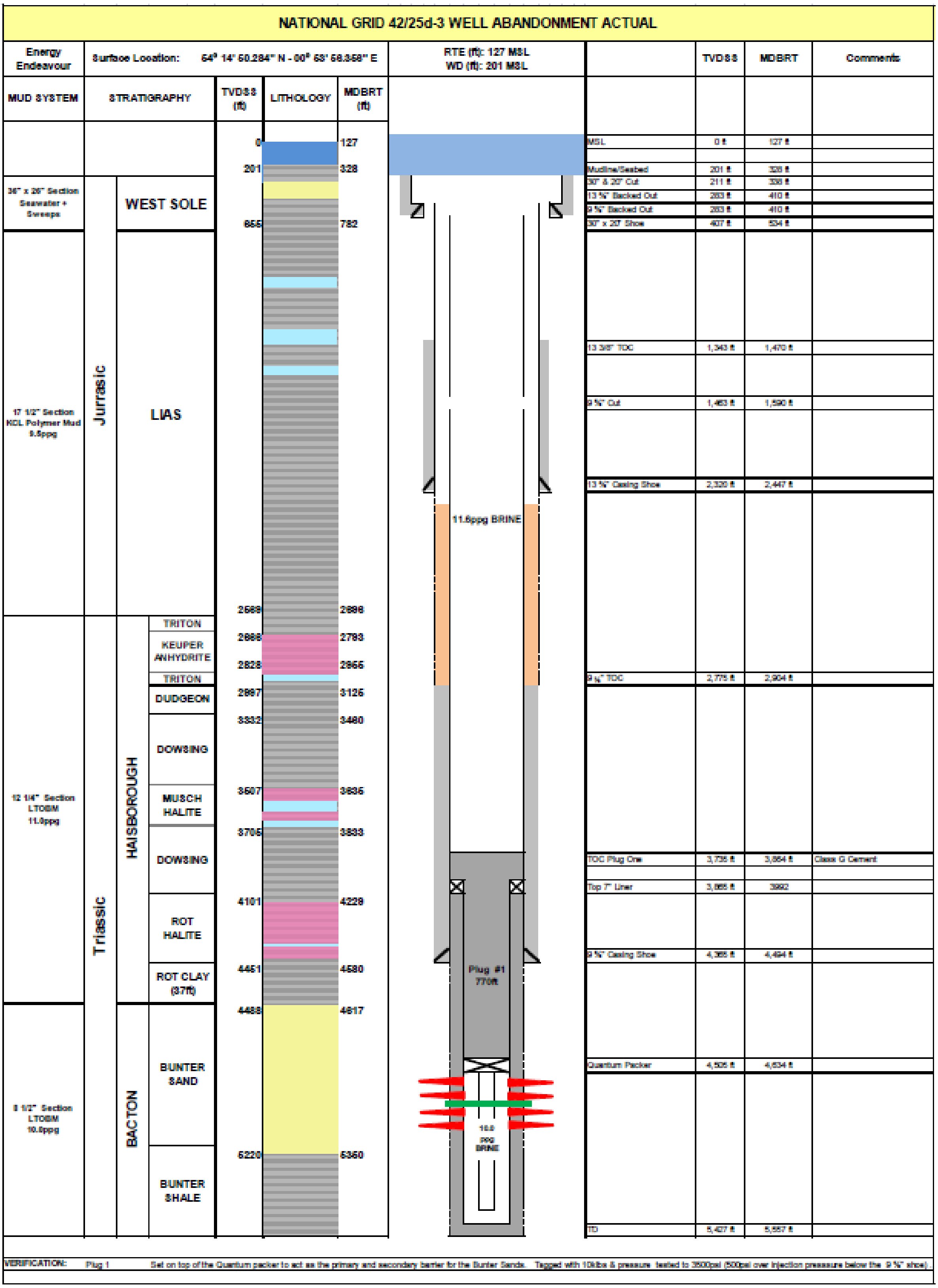


Figure 12 42/25d-3 Abandonment Schematic

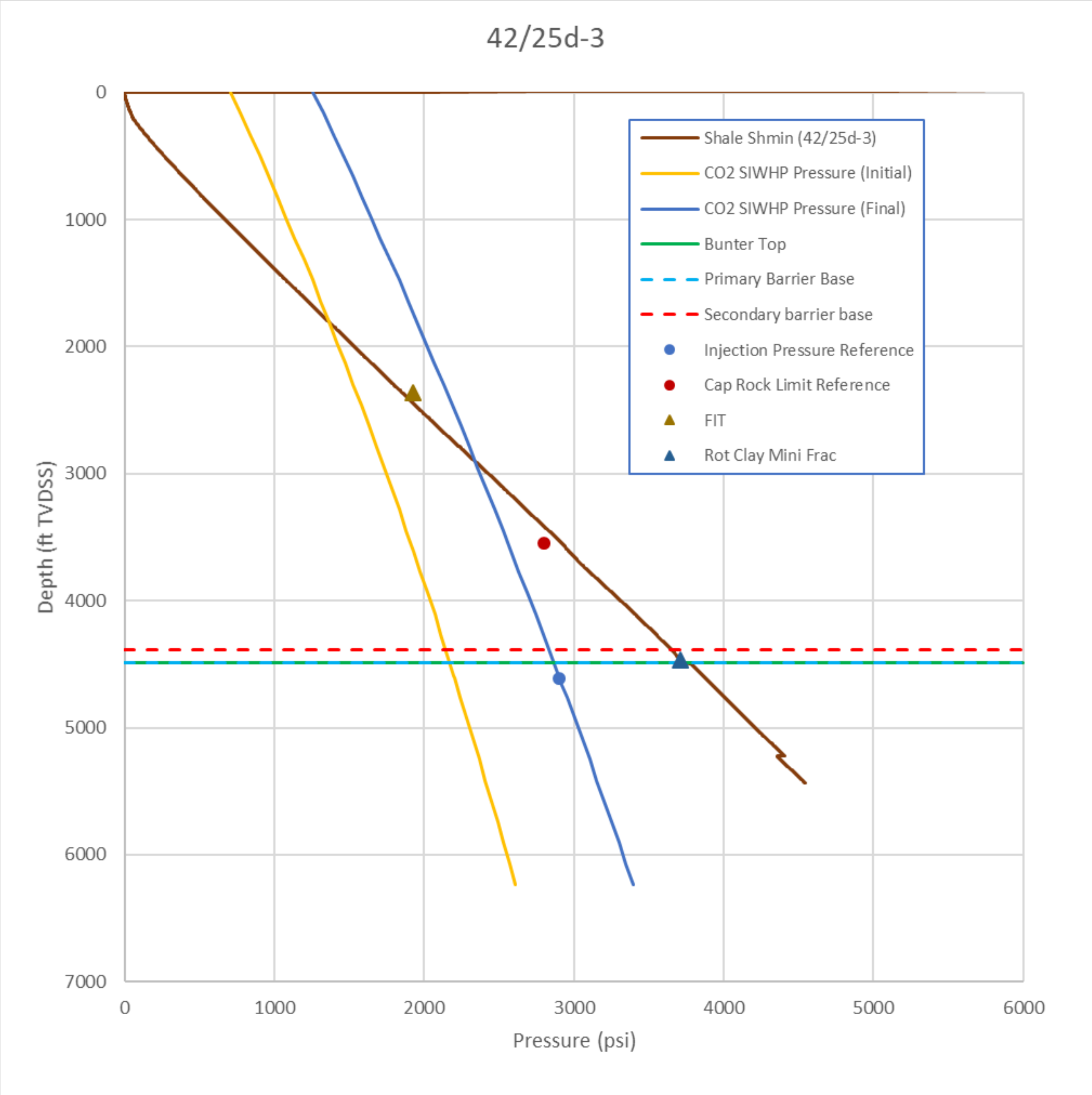


Figure 13 Well 42/25d-3 CO_2 Initial and Final Injection Pressure vs. Shale S_{hmin} Pressure

8.3.2 Abandonment Assessment

This well's casing strings were all made of carbon steel and cemented throughout with Class G cement, but only the conductor was cemented back to the surface. The other casings were cemented around the shoe, but the cement did not reach the shoe of the overlying casing string. This well was abandoned by a single cement plug set atop a packer and the remainder of the wellbore left with 11.6ppg brine. This leaves approximately 25m of the Bunter sandstone below the packer exposed to the wellbore which at this depth is filled with 10ppg brine. It is also worth noting that the 9 ⅝in casing was punched through at 694m (above the top of the cement) creating a direct annulus to wellbore path. Furthermore, all casing strings were cut below the mudline.

Wellbore Zonal Isolation:

- The packer (2 ¼” ID) along with an LCM pill did not provide a sufficient base for the 770ft (originally planned as 1,000ft) cement plug, as cement was tagged 249ft deep and an estimated +/- 20bbls of cement passed through the packer.
- The 30” x 20” conductor was cut at 338ft, and the 13 3/8” and 9 5/8” casing strings were backed out at 410ft.
- Although milling a window in the 7” liner and setting of a pancake plug was originally planned as part of the abandonment, upon review of the Bunter sandstone structure, National Grid stated that any future CO_2 injection or resultant acidic formation water would not reach the location of the 42/25d-3 well. It was therefore decided to abandon the well in accordance with Oil & Gas UK guidelines with no milling or pancake plug over the caprock.

Annulus Zonal Isolation:

- Cement returns to the sea floor were noted on the 30” x 20” conductor job, giving confidence that this annulus was fully cemented.
- Both the 13 3/8” and 9-5/8” cement jobs did not have their plugs bumped and estimates of TOC is provided in the EOWR, although no verification method has been indicated.
- 9-5/8” Casing was cut at 1590ft (after failed wireline perforation attempt) and the annulus circulated. To displace and clean the annulus, 37bbl of wash pill was pumped before shutting in the annular. The side outlet valve was opened, and the annular volume circulated with a further 43bbl of wash pill. This was chased by 100bbl 11.6ppg brine at 232gpm, 550psi. Clean returns were seen after 10bbl brine pumped.

8.3.3 Summary

Although the 42/25d-3 well was not optimized for long-term storage of CO_2, it has been abandoned with two barriers to the Bunter, albeit with some uncertainties regarding the abandonment in general. Points of Note:

- No documentation of annular barrier verification
- Wellbore barrier verified by tagging and pressure testing but no inflow testing
- Upon review of the Bunter sandstone structure, National Grid stated that any future CO_2 injection or resultant acidic formation water would not reach the location of the 42/25d-3 well. It was therefore decided to abandon the well in accordance with Oil & Gas UK guidelines with no milling of the 7” liner or a pancake plug.
- Based on the identified potential leak paths from the Bunter formation and the well barrier elements and envelopes present, both primary and secondary annulus and wellbore containment is present, but not necessarily verified as per current practice.
- Although it can be expected across the field, there is no evidence that the West Sole sand (shaded yellow) as shown in the P&A schematic across the 30” x 20” conductor section was present on the 42/25d-3 well. Its lack of presence on logs in the other legacy wells supports this assumption. If this sand is encountered on the new wells drilled as part of the NEP project, it will be taken into consideration for the future abandonment program.

8.4 42/25-1

8.4.1 Well Data

Well Attribute	Data	
Surface Location	Latitude 54° 13' 44.87" N Longitude 0° 58' 46.68" E	
Operator	BP Exploration	
Drilling Unit	West Kappa	
Spudded	18 September 1990	
Abandoned	9 October 1990	
Duration (Well Construction)	21 days	
Formation Pressure		
Total Depth	1195m MD BRT	
Water Depth	59.20m (Lowest Astronomical Tide)	
Derrick Floor Elevation	35.43m	
Maximum Inclination	2.5° at 1195m MD	
Casing Details		**Weight – Grade – Threads**
30" Conductor	160m	310/450ppf – X-52 – H90
13 3/8" Casing	557m	54.5ppf – K55 – BTC
Cement Details		
30" Cement Job	Class G (2% $CaCl_2$) 1422 cu. ft. @ 1.92 sg	Returns to seabed verified by ROV. No known centralizers
13 3/8" Cement Job		
Lead	Class G 1742 cu. ft. @ 1.34 sg	TOC calculated based on volumes pumped. CBL (517.9m – 81m) – no results available. No known centralizers
Tail	Class G 644 cu. ft. @ 1.92 sg	
Final Differential Pressure		
Pressure Test		
Abandonment		
Plug 1	Class G 11.5 m^3 @ 1.92 sg 1195m – 1045m	
Plug 2	Class G 11.6 m^3 @ 1.92 sg 607m – 508m	
Plug 3	Class G 4.5 m^3 @ 1.92 sg 180m – 125m	

Table 7 Well 42/25-1 Data

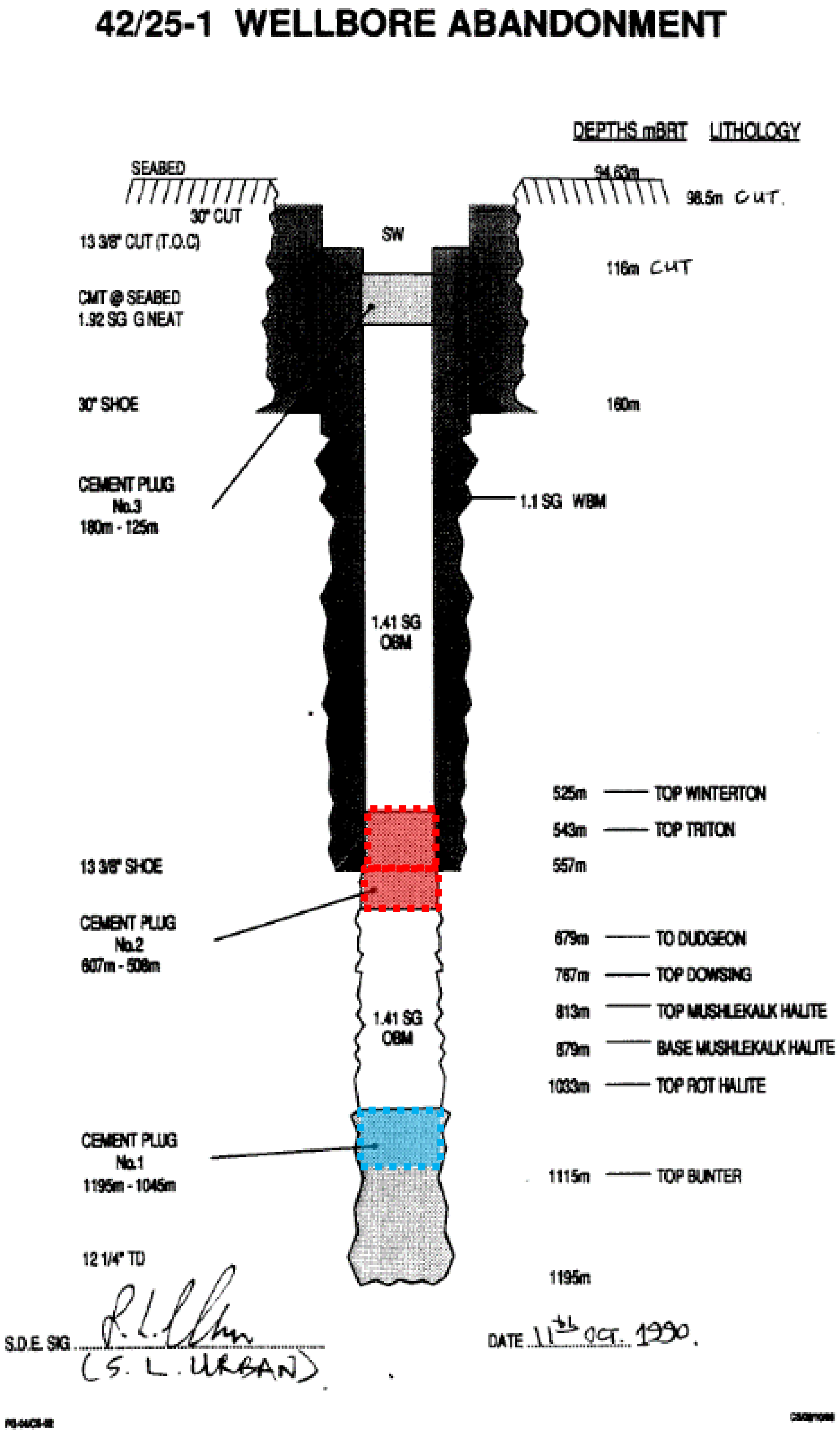


Figure 14 42/25-1 Abandonment Schematic

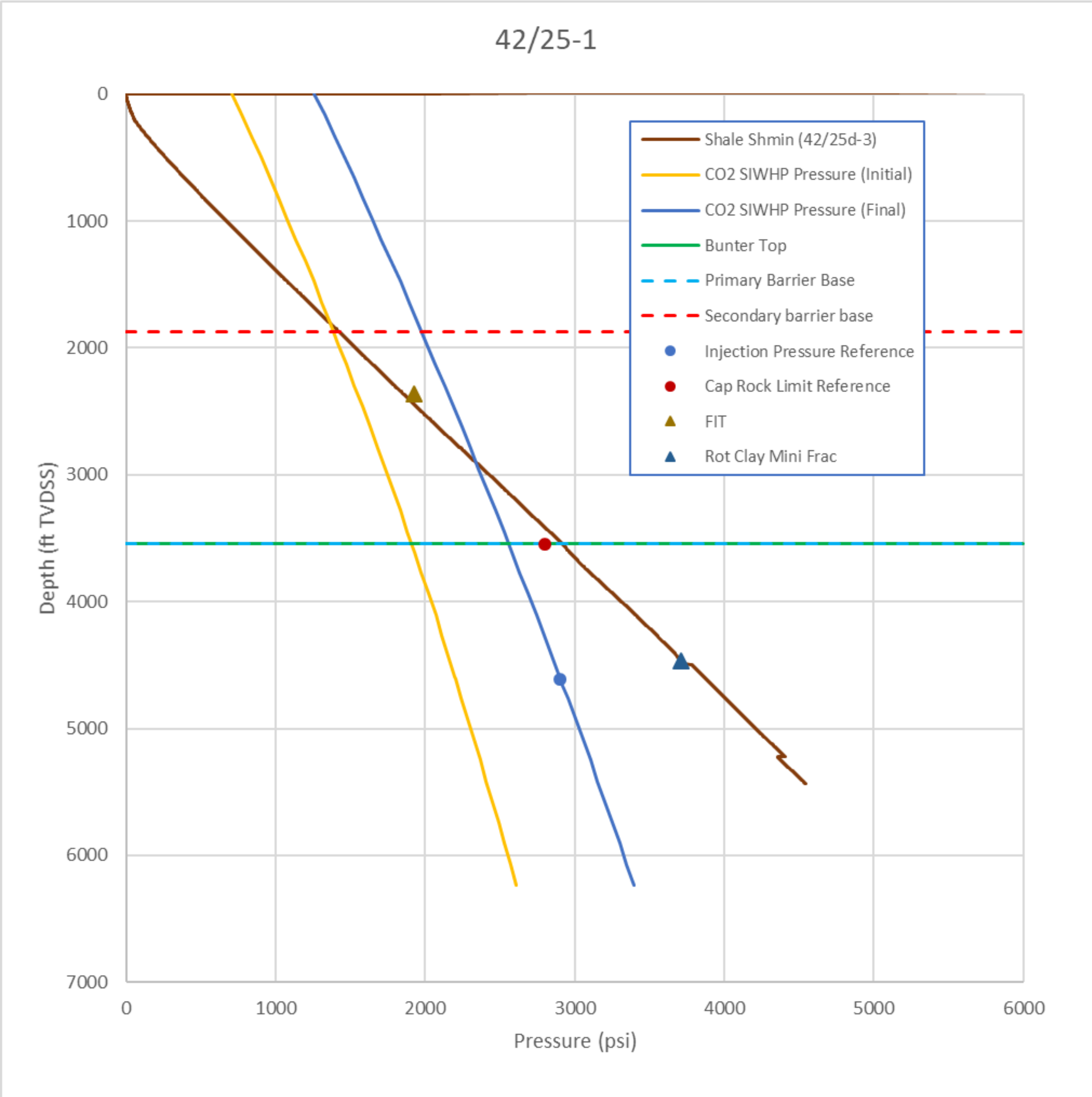


Figure 15 Well 42/25-1 CO_2 Initial and Final Injection Pressure vs. Shale S_{hmin} Pressure

8.4.2 Abandonment Assessment

The shallower parts of the well were cased, but the 12 ¼ in diameter section that passes through the Bunter sandstone is not cased. This well was abandoned by a total of 3 cement plugs; one shallow plug, one at the casing shoe and one across the top of the Bunter sandstone into the Röt Halite. The inter-plug fluid is oil-based mud (11.74ppg) with seawater above the shallowest plug. Furthermore, both casing strings were cut below the mudline. All casing strings are made of carbon steel and the cement used was standard "Class G".

Wellbore Zonal Isolation:

- Plug #1: The lower portion of the open hole section of this well was abandoned via a single cement plug from well TD (1195m) to 1045m. No documentation is available of what verification methods were used.
- Plug #2: A ~100m cement plug was then set across (50m above and 50m below) the 13 3/8" shoe (607m – 508m). The plug was weight tested to 15Klbs and pressure tested to 1,000psi, but there is no evidence that the plug was set on any base.
- Plug #3: A further 55m plug was set ~30m below the mudline (180m – 125m), but there is no evidence that the plug was set on any base. Also, there is no documentation available of what verification methods were used.
- Based on their positioning, all 3 plugs play some part in containing CO_2 from primary entry points into the well.
- The 13 3/8" and 30" casings were all cut and retrieved at 116m and 98.5m respectively.

Annulus Zonal Isolation:

- Cement returns to the sea floor were noted on the 30" cement job, giving confidence that the annulus was fully cemented.
- The available information indicates that the 13 3/8" cement job went "as per planned", and TOC was calculated based on volumes pumped.
- It was recorded that a CBL log was run inside the 13 3/8" casing (from 517.9m – 81m) but no results from this log are available.

8.4.3 Summary

This well targeted the Bunter sandstone on structure, and has a primary barrier isolating the Bunter sandstone in open hole, and a secondary barrier across the open hole and 13 3/8" casing at the shoe. The fracture gradient at the secondary barrier would not withstand final CO_2 injection storage pressure, and so it is concluded that along with uncertainties regarding the abandonment in general, the well has only one barrier to CO_2 leakage from the store. Points of Note:

- The desired final cessation of injection pressure would exceed the fracture pressure at the base of the secondary barrier.
- Limited documentation of annular barrier verification exists: 30" cement job was verified through cement seen at surface via ROV and 13 3/8" TOC calculated based on volumes pumped.
- Limited documentation of wellbore barrier verification exists: Although Plug #1 was set on bottom, there is no evidence of what verification methods were used. Plug #2 was weight and pressure tested but there is no evidence of a reliable base being used. Plug #3 has no documentation of what verification methods were used
- Based on the identified potential leak paths from the Bunter formation and the well barrier elements and envelopes present, both primary and secondary annulus and wellbore containment is present, but not necessarily verified as per current practice.

8.5 43/21-1

8.5.1 Well Data

Well Attribute	Data	
Surface Location	Latitude 54° 13' 00.362" N Longitude 0° 00' 19.143" E	
Operator	Mobil	
Drilling Unit	BP/Sea Quest	
Spudded	19 February 1970 (2130 hrs)	
Abandoned	18 March 1970 (0600 hrs)	
Duration (Well Construction)	26 days 8 hours 30 min	
Formation Pressure		
Total Depth	4470ft MD RTE	
Water Depth	184ft MSL	
Derrick Floor Elevation	112ft MSL	
Maximum Inclination	3° at 4470ft	
Casing Details		**Weight – Grade – Threads**
30" Conductor	392ft	309ppf – 1" wall – Welded
13 3/8" Casing	1798ft	68ppf – N80 – BTC
Cement Details		
30" Cement Job	Class B (2% $CaCl_2$) 500 sxs / 21 long tons @ 1.93 sg	Returns to surface, no evidence of ROV verification. No centralizers
13 3/8" Cement Job		
Lead	Class B (8% gel) 800 sxs / 33.6 long tons @ unknown density	Full returns whilst cementing TOC at 305ft
Tail	Class B 500 sxs / 21 long tons @ unknown density	TOC at 1375ft
Final Differential Pressure		
Pressure Test		
Abandonment		
Plug 1	Class B ($CaCl_2$) 250 sxs 3644ft – 3300ft	
Plug 2	Class B ($CaCl_2$) 374 sxs 1962ft – 1516ft	Checked top of plug with 30Klbs
Plug 3	Class unknown Unknown sxs 655ft – 370ft	

Table 8 Well 43/21-1 Data

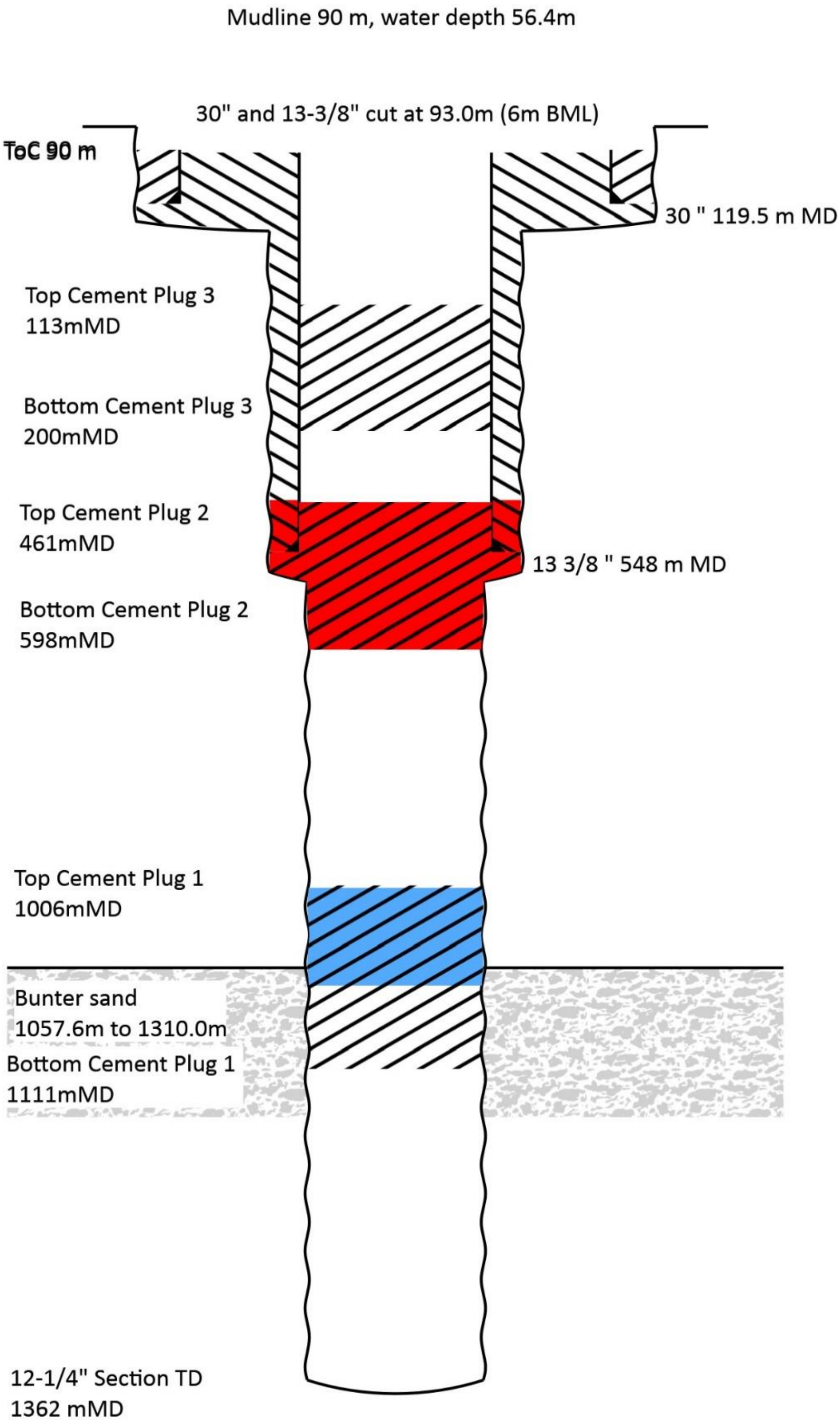


Figure 16 43/21-1 Abandonment Schematic

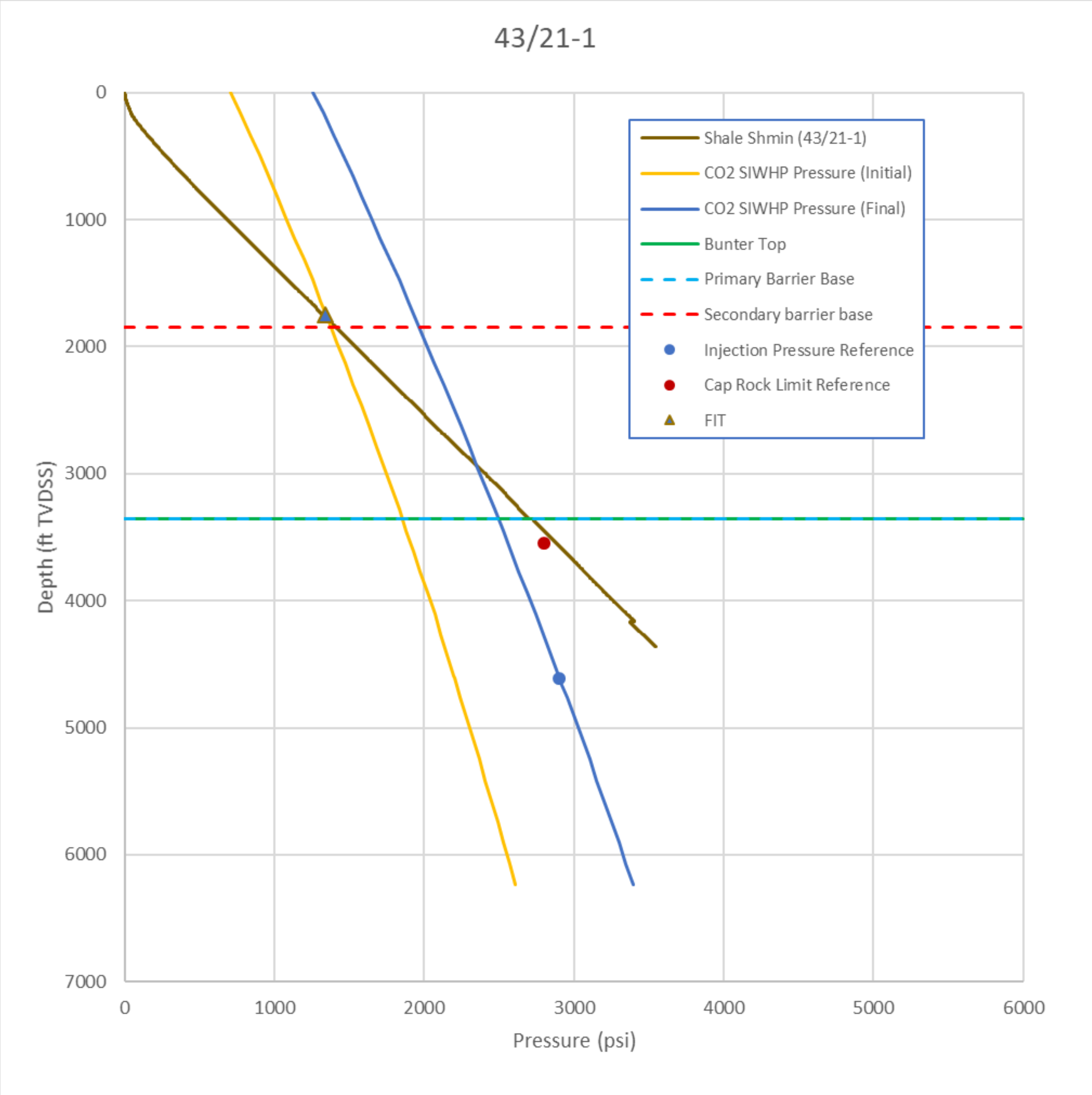


Figure 17 Well 43/21-1 CO_2 Initial and Final Injection Pressure vs. Shale S_{hmin} Pressure

8.5.2 Abandonment Assessment

This well was abandoned by a total of 3 cement plugs; one shallow plug, one located at the casing shoe and one across the top of the Bunter sandstone into the Röt Halite. Furthermore, all casing strings were cut below the mudline. All casing strings are made of carbon steel and the cement used around the casings and for plugs was Class B cement, based on API Specification 10A, which is similar to ASTM Specification C150 Type II cement.

- API Class B cement is equivalent to Type 2 cement; in construction, it is used for structures in water or soil containing moderate amounts of sulphate, or when heat build-up is a concern
- API Class B cement is chemically very close to API Class G/H cement. It is a bit finer than Class G and Class H and therefore mixed at 15.6 ppg rather than 15.8 ppg for Class G and 16.4 ppg for Class H

- Due to its slightly lower C3S %, it should react a bit slower than a Class A, G or Class H cement

Overall, Class B set cement properties and chemical interaction with CO2 are very similar as for a Class G set cement.

API Class	C3S %	C2S %	C3A %	C4AF %	Fineness (cm2/g)	Special Application
A	53	24	8	8	1,550 to 1,900	none
B	47	32	5	12	1,550 to 1,900	Sulfate resistant
C	58	16	8	8	2,000 to 2,800	Early setting
D&E	26	54	2	12	1,200 to 1,600	Retarded
G&H	50	30	5	12	1,400 to 1,700	More stringent specs

Table 9 Properties of API Portland Cements

Wellbore Zonal Isolation:

- Plug #1: The first open hole plug set in this wellbore was set off bottom from 3644ft – 3300ft. There is no documentation stating that the plug was set with any kind of bottom support (viscous pill) and nor was it tagged or pressure tested.
- Plug #2: A 446ft cement plug was then set across the 13 3/8" shoe (1962ft – 1516ft). The plug was weight tested to 30Klbs, but there is no documentation to confirm that the plug was set on any base nor pressure tested. The plug was reported tagged 81ft (24.7m) deeper than volumetric calculations suggested.
- Plug #3: A further 285ft plug was set 75ft below the mudline (655ft – 370ft), but there is no evidence that the plug was set on a base, nor is there documentation available of what verification methods were used.
- Based on their positioning, only plugs # 1 and 2 play some part in containing CO_2 from primary entry points into the well via the Bunter formation.
- Seawater is the fluid above the shallowest plug. It is not known what the inter-plug fluid is, but the last section of the well was drilled with a salt-saturated XC polymer system and it is possible that this fluid, or a cleaned and circulated version of this fluid, has been left in hole following abandonment of the well.
- The 13 3/8" and 30" casings were cut and retrieved at 305ft (10ft BML).

Annulus Zonal Isolation:

- Cement returns to the sea floor were noted on the 30" cement job, giving confidence that this annulus was fully cemented.
- The available information indicates that the 13 3/8" cement job went "as per planned" as full returns were noted throughout the job.

8.5.3 Additional Work for 43/21-1

Due to the fact that there are no records of the primary plug being set on a base in this well, further work was undertaken to simulate the plug placement and to calibrate it with the known data for the secondary plug.

As additional assurance, a geomechanics study evaluating the potential for the Rot Halite cap rock to "creep" and re-instate the natural seal was also carried out. This latter study is also relevant to all wells on and off structure and gives additional confidence in isolation status.

This work is presented in the following sections.

8.5.4 Cement "Slumping"

There are no records that state if the abandonment plugs were set on a base (e.g. a viscous pill); although it is unlikely that this would not be the case as it was and is basic cementing practice and it is more likely that record keeping was less thorough.

It is known that the plug 2 was tagged 81ft or 24.7m deeper than calculated; this could have been due to slumping, but it is more likely that the upper portion of the plug was just contaminated cement forming around the drill pipe as it is pulled through the plug when coming out of hole. If plug 2 had not been set on a viscous pill, it would have slumped rapidly and would not have been there to tag.

There are currently no slumping simulators that can model this well; Schlumberger can do some limited assessment with their "Cementics" software, but cannot model timescales longer than 2 minutes, and cannot model an open hole depth below the plug greater than 20m at present.

Nevertheless, a standard cement placement simulation was done for both plug 1 and plug 2 with inputs from well data where available, or assumed normal practice where not:

Plug 2:

- Plug set at 1,962 ft (598m)
- Deviation as per deviation summary ~2 ½ deg
- 12 ¼" open hole without excess
- 10.5 ppg mud (Pv = 16 cP, Yp = 32 lbs/100 ft2, 10 min gel =19)
- 15.6 ppg Cement (Pv = 80 cP, Yp = 19 lbs/100 ft2)
- 78.6 bbl of cement (374 sks of Class B cement)
- 20 bbl of water ahead, water behind to balance, 2 bbl under-displacement, pump rate 5 BPM
- Drill pipe 5in 19.5 ppf, POOH speed 33 ft/min

Figure 18 43/21-1 Secondary Abandonment Plug 2 Placement Simulation

The simulation output shown in Figure 18 suggests 44 ft (~13m) of contaminated cement at top of the plug due to mixing with mud when POOH, which is of a similar order to the reported tag for this plug at 81 ft (24.6m) deep.

Plug 1:

- Plug set at 3,644 ft (1110m) in 12 ¼" open hole without excess
- Deviation as per deviation summary ~2.5 deg
- 10.5 ppg mud (Pv = 16 cP, Yp = 32 lbs/100 ft2, 10 min gel =19)
- 15.6 ppg Cement (Pv = 80 cP, Yp = 19 lbs/100 ft2)
- No high vis pill / reactive pill set below the plug
- 52.5 bbl of cement (250 sks of Class B cement)
- 20 bbl of water ahead, water behind to balance, 2 bbl under-displacement, pump rate 5 BPM
- Drill pipe 5in 19.5 ppf, POOH speed: 33 ft/min

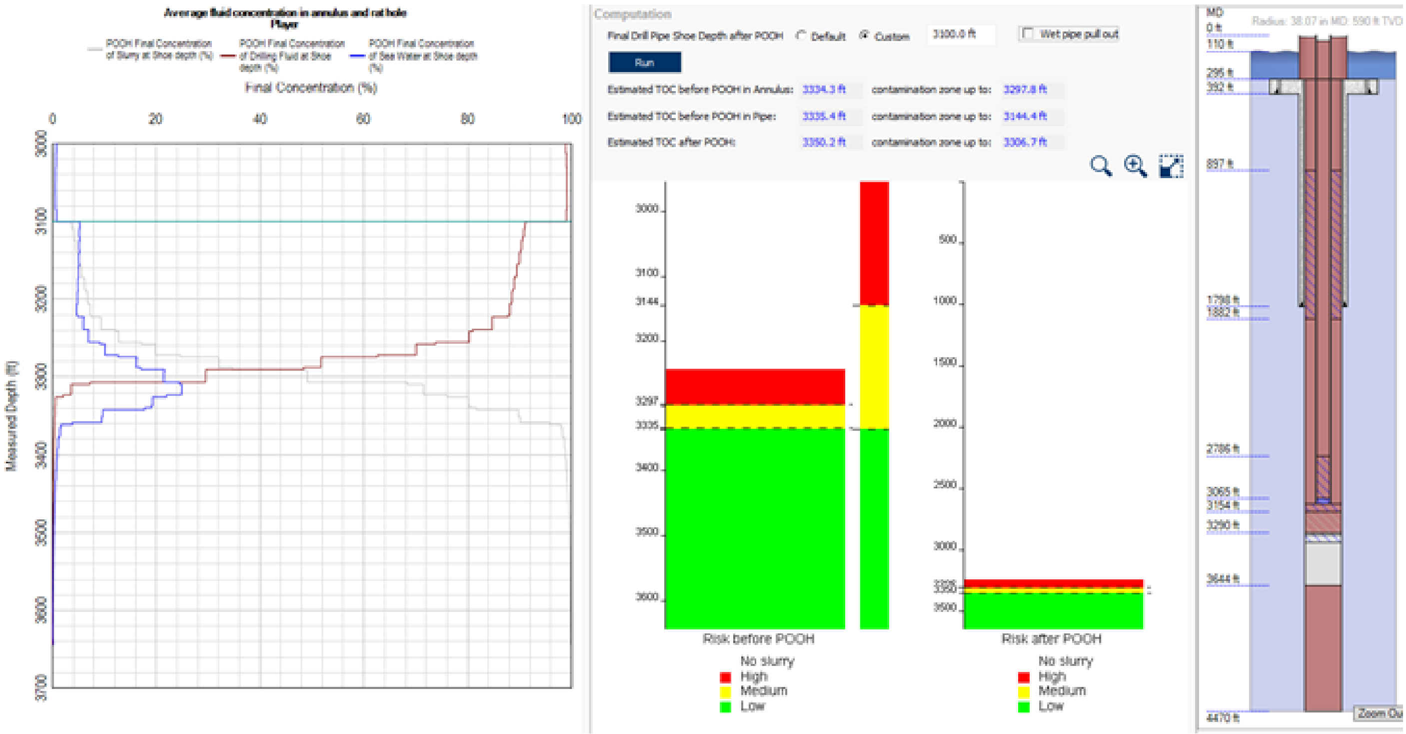


Figure 19 43/21-1 Primary Abandonment Plug 1 Placement Simulation

The simulation output shown in Figure 19 suggests 67 ft (~20m) of contaminated cement at top of the plug due to mixing with mud when POOH, which is also consistent with the 81 ft deep reported tag for plug 2 above it.

To be conservative, rather than assuming 67 ft of contaminated cement for plug 1, the plug 2 tagged analogue of 81 ft was used to calculate a corrected top for plug 1 as shown in Table 10 for the QRA.

	Plug No 1	Plug No 2
Depth reported (Top-Bottom)	3,300 – 3,644 ft	1,516 – 1,962 ft
Length	344 ft	446 ft
Sacks pumped	250 sks	374 sks
Slurry yield (assumed for a Class B cement)	1.18 cuft/sk	1.18 cuft/sk
Slurry volume pumped (sks x yield)	52.5 BBL	78.6 BBL
Theoretical TOC (assuming no open hole excess)	3,283 ft	1,435 ft
Calculated slump (TOC reported – theoretical)		81 ft (24.7m)
Plug 1 estimated TOC based on Plug 2 slump	3,364 ft (1025m)	
Length of cement above Top Bunter	104 ft (31.7m)	

Table 10 Well 43/21-1 Corrected Plug 1 Top Estimate

Based on this estimate, it may be expected that 104ft (31.7m) of cement would still be present above the top of the Bunter across the cap rock.

8.5.5 Summary

43/21-1 targeted the Bunter sandstone on-structure, and has a primary barrier isolating the Bunter in open hole, and a secondary barrier across the open hole and 13 3/8" casing at the shoe. The fracture gradient at the secondary barrier would not withstand final CO_2 injection storage pressure, and so it is concluded that along with uncertainties regarding the abandonment in general, the well has only one cement barrier to CO_2 leakage from the store at final abandonment pressure. Points of Note:

- Limited documentation of wellbore barrier verification exists. Only Plug #2 was recorded as having been weight tested
- Plug 1 provides the primary barrier to CO2 in the Bunter. There are no records indicating if it was set on a base or not, and was not verified by pressure testing nor a tag. Although it is predicted to have ~67ft of contaminated cement in the top part of the plug, the corrected length of the upper plug 2 was used as a more conservative calibration point. This means that 31.7m of cement may be expected to be present above the Bunter across the cap rock, which in itself would meet current guidance of a minimum height of 30m.
- Plug 2 placement was also modelled for completeness, which indicated that 44ft (13m) of contaminated cement may be expected at the top of the plug.
- The desired final cessation of injection pressure would exceed the fracture gradient of the rock at the base of the secondary barrier.
- The 30" cement job was verified through cement seen at surface and 13 3/8" TOC calculated based on theoretical values.
- The Rot Halite is expected to form a secondary seal, and validation work is described later in this document in Section 10.

9 Brine Pressurisation

The risk of CO2 leakage via a leak path associated with a legacy well is primarily a risk for the on-structure wells as the off-structure wells should not see any CO2 assuming the plume does not migrate beyond the spill point. The off-structure wells will however experience an increase in pressure in the brine within the Bunter sandstone due to displacement of brine by CO2 from Endurance into the regional aquifer.

To understand this further, the pressure in the Bunter was evaluated for a sample of 13 off-structure wells for a number of injection scenarios covering different aquifer connectivity possibilities at store closure (25 years after injection start) and 25 and 250 years after closure.

The worst case (largest) brine pressure increases generally corresponded to the case where downside reservoir properties (i.e. poor connectivity) had been assumed and at store closure (25 years after first injection). A pressure map of this scenario is shown below in Figure 20

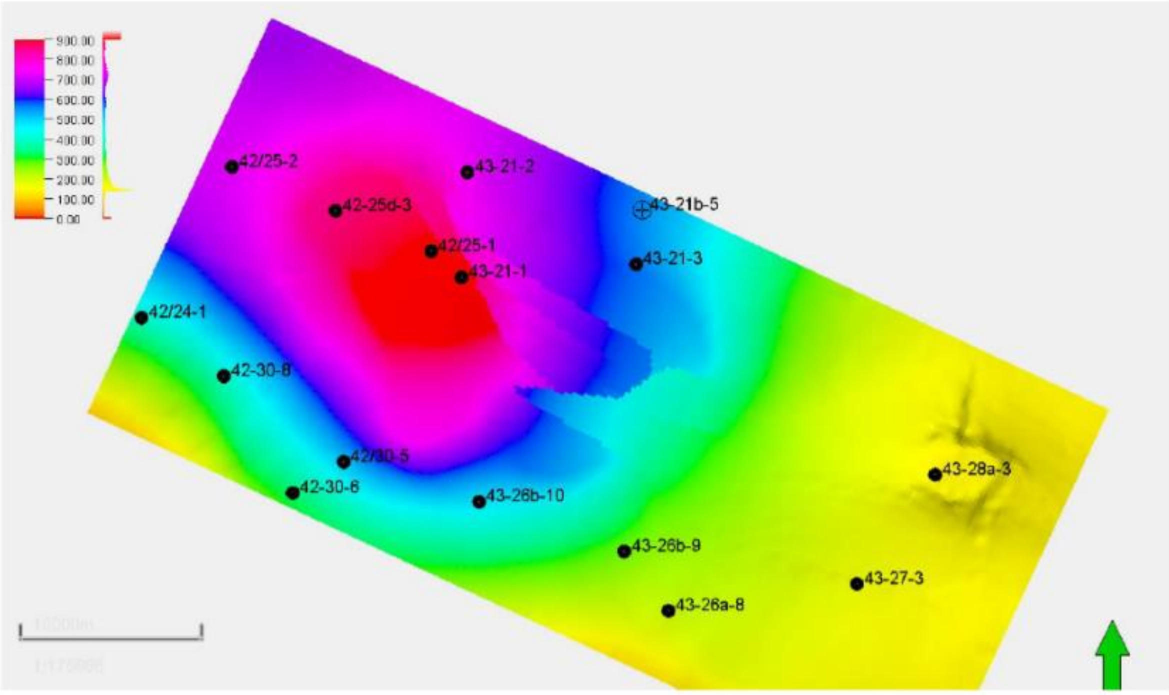


Figure 20 Worst Case Brine Pressurisation Map (after 25 years injection at store closure)

The pressure dissipation over time was then modelled, with worst-case reservoir connectivity (longest time to decline) presented in Figure 21 to Figure 22, which indicates that the regional pressure outside of the storage complex declines over time with ever-reducing risk to leakage due to loss of driving over-pressure.

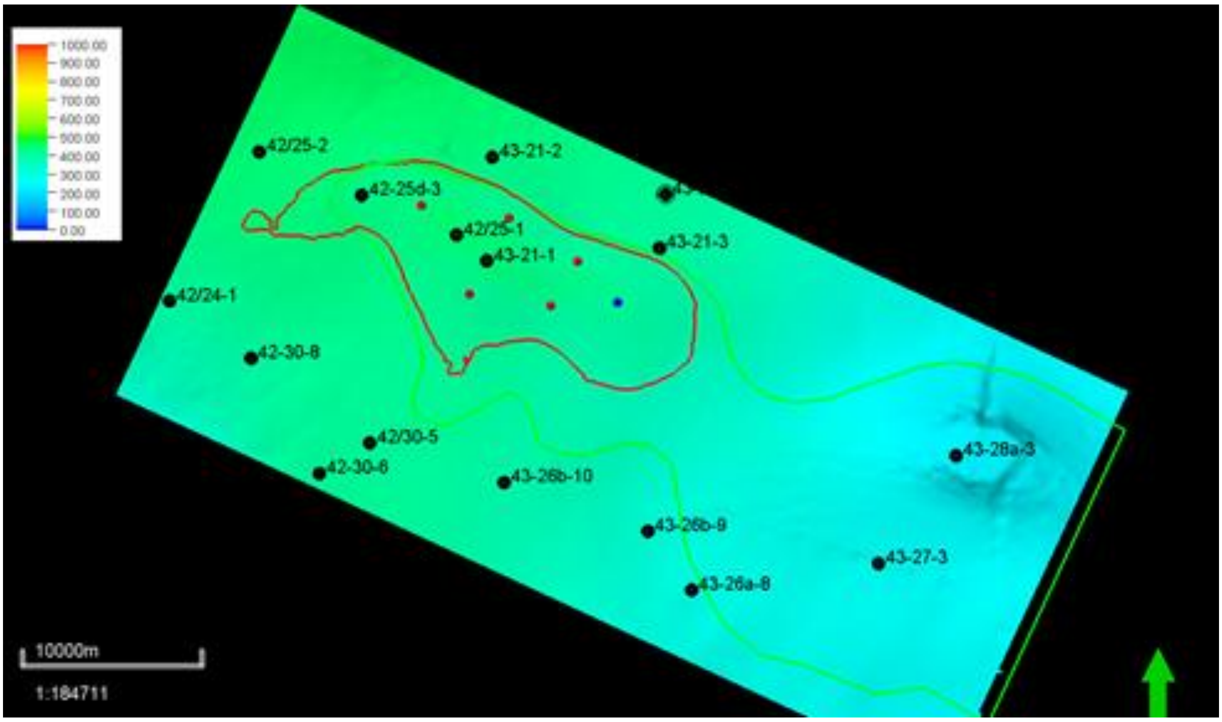


Figure 21 Worst Case Brine Pressurisation Map (25 years after closure)

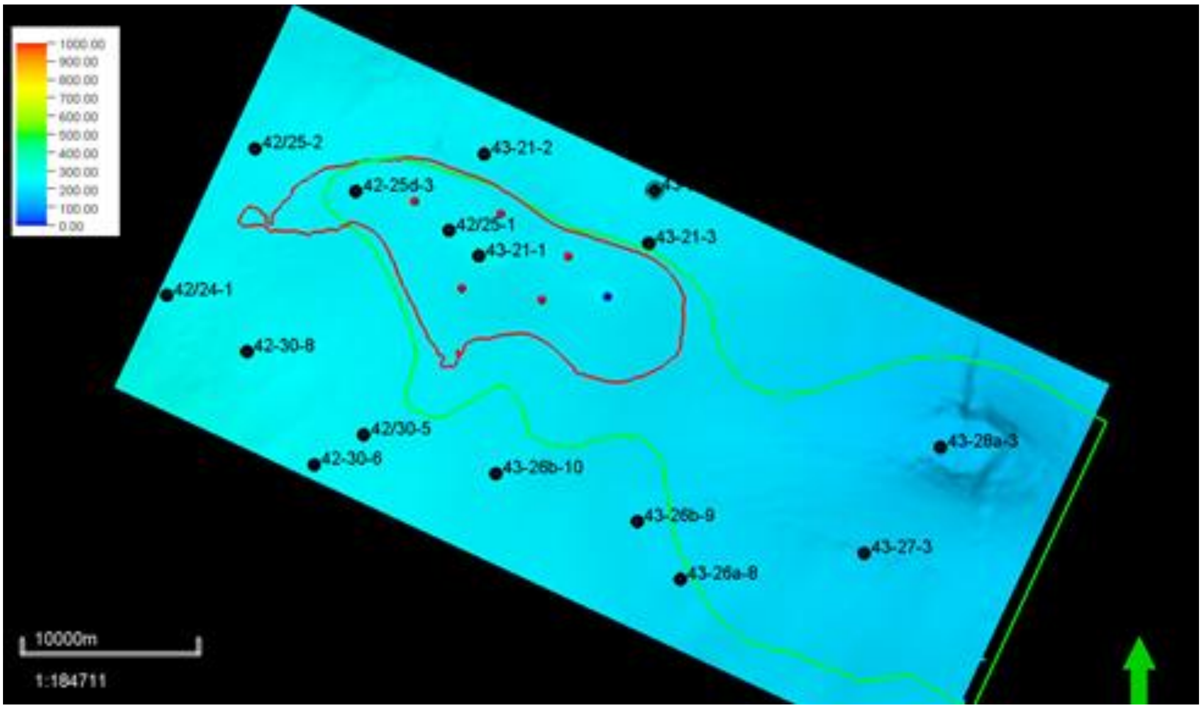


Figure 22 Worst Case Brine Pressurisation Map (250 years after closure)

Table 11 below summarises the legacy wells considered, the initial over-pressure expected after CO2 injection has ceased and the isolation status of the Bunter from an annulus and lateral isolation perspective. The following points are noteworthy:

- Brine over–pressure taken as highest of reservoir down–side, base and upside, base and upside cases after 25 years injection at cessation of injection with no brine production (i.e. most conservative)
- Vertical isolation length taken as the shortest of the top of the Bunter to Shmin, previous shoe or TOC (i.e. most conservative)
- Approximately ~150 psi over–pressure at datum depth required to balance brine column to seabed depending on water depth.
- All wells (aside from 43/28a within the outcrop itself) have their previous shoe (prior to entering the Bunter) set at a depth where the formation is capable of withstanding the increased brine pressure (according to the LOT / FIT / Shmin data available) should annular cement not be present or not act as an effective barrier
- Halite creep is expected and may provide further isolation (see Section 10)
- Saline brine is anoxic so a low corrosion risk is expected (see Section 9.1)
- Long cemented intervals may mitigate against annular defects

Well	OP (psi)	Annular Isolation	Lateral Isolation	Comments
43/21-2	800	1078m 13 3/8" annular cement isolation to Shmin below 20" Shoe	200m plug at mudline	OP crosses Shmin below top of annular cement. 13 3/8" cement column extends to casing cut below mudline
43/21-3	600	739m annular cement isolation to FIT at 13 3/8" shoe	None	OP < Shmin and FIT across cemented annular interval
43/21b-5	500	1147m 9 5/8" annular cement	None	OP < Shmin across cemented annular interval
42/25-2	700	742m 13 3/8" annular cement to 20" Shoe	None	OP < Shmin across cemented annular interval
42/24-1	450	681m 13 3/8" annular cement to 20" Shoe	None	OP < Shmin across cemented annular interval
42/30-8	450	No annular cement. Isolation at 18 5/8" shoe	Plug at mudline (length unknown)	OP < LOT at 18 5/8" shoe
42/30-6	550	Unknown (no cement data or schematic). Assume same as 42/30-8 for conservatism	Unknown	OP < LOT at 18 5/8" shoe
42/30-5	600	419m 13 3/8" annular cement to TOC	Unknown	OP < LOT at 18 5/8" shoe and < Shmin across cemented annular interval
43/26b-10	550	836m annular cement isolation to 13 3/8" Shoe	200m plug at 13 3/8" shoe	OP crosses Shmin below top of cemented annular interval
43/26b-9	400	Unknown (no cement data or schematic)	Unknown	OP < FIT at 13 3/8" shoe
43/26a-8	350	Unknown (no cement data or schematic)	Unknown	OP < FIT at 13 3/8" shoe
43/27-3	250	Unknown (no cement data or schematic)	Unknown	OP < FIT at 13 3/8" shoe
43/28a-3	250	None - this well is at the outcrop. Bunter at mudline	None	Brine will flow outside of well conductor envelope as this well is drilled through the outcrop anyway – leakage calculations are not relevant
43/21a-4	800	875m 13 3/8" Cement to Shmin below 20" shoe	Unknown	OP crosses Shmin below top of cemented annular interval
42-25a-G1	800	618m 13 3/8" annular cement to TOC	None	20" x 13 3/8" annulus open to seabed above TOC
42/25a-G2	800	633m 13 3/8" annular cement to TOC	None	20" x 13 3/8" annulus open to seabed above TOC

Table 11 Off-Structure Brine Pressurisation Well Status

9.1 Corrosion of Off-Structure Legacy Well Casing Strings

This section is précised from a technical note evaluating the long-term casing corrosion threat in two example off-structure wells (43/21-2 and 43/21-3) exposed to brine.

Without CO2 or O2 contamination, the Bunter aquifer water is anticipated to be a near-neutral brine that is relatively benign to the production casing with a minimal corrosion threat. Corrosion of the outer casing of both wells (13 3/8") would be impeded by the 13 3/8" annular cement. Where the cement is present, even if porous and providing a leak path through to the casing will present a tortuous path for water access. Provided that the cement provides an adequate barrier to flow up the 13 3/8 inch annulus, then corrosion of the 13 3/8 inch casing will be extremely limited:

- Corrosion that has already occurred will have saturated the occluded fluids with iron, further reducing the already limited corrosion rates.
- Corrosion will be dominated by the diffusion of the rate-dictating species (for example dissolved CO2, O2, and iron ions). Diffusion rates in the absence of flow are extremely slow and the flow of water in contact with the casing is anticipated to be very limited[3].

Fundamentally, pressurisation alone of the brine will not change the anticipated corrosion rates and corrosion rates would be expected to be remain extremely slow. However, corrosion rates cannot be said to be zero if there is contact with the aquifer water. Some minor corrosion could occur and over centuries this could lead to perforation of the 13 3/8 inch casing local to the Bunter sands.

The aquifer brine would increase in corrosivity, if dissolved CO2 increases, but this will not occur as the CO2 plume will be monitored to ensure it does not migrate under the spill point.

For well 43/21-2, there is additional cement between the 13 3/8" and 9 5/8" casing (9 5/8" annular cement). This creates an additional barrier to leaks created by any corrosion in the 13 3/8 inch casing. Assuming that the 9 5/8 inch annular cement is adequate to prevent flow up the annulus, then the barriers would only be compromised if there is through-wall corrosion of both the 13 3/8 inch and 9 5/8 inch casing. In other words, two cement barriers and two casing barriers would need to be compromised. The arguments presented for limited corrosion rates of the 13 3/8 inch casing apply even more so to the 9 5/8 inch casing; the flow of water and diffusion of species is expected to be even more limited. If corrosion did result in perforation of the 9 5/8 inch casing (local to the Bunter sands) then corrosion higher up in the well may be mitigated by the completion/abandonment fluid left in the well.

Some consideration should be given to the abandonment fluids within the 9 5/8 inch casing. If these fluids were selected and employed using reasonable practice then corrosion within the bore of the casing is expected to be extremely limited. Of particular importance is the potential for microbiologically-influenced corrosion (MIC). Typical brines include a biocide or are of a great enough density to inhibit the reproduction of micro-organisms and the threat of corrosion, particularly due to sulphate-reducing bacteria (SRB). The 1.2 SG brine reported to be in Well 43/21-2 is likely of sufficient density to inhibit reproduction of SRB. There is no information regarding the abandonment fluid in 43/21-3.

[3] Another source of corrosion is galvanic corrosion due to dissimilar metals on the casing string. This is unlikely since both 9 5/8" and 13 3/8" casing are of similar metallurgy.

It is difficult to estimate through-wall corrosion rates with respect to very long exposure periods. However, adequate cementing and relatively benign fluids typically result in <0.1 mm/Yr corrosion rates.

9.1.1 Conclusions

Provided that the 13 3/8" and 9 5/8" annular cement is adequate to prevent flow up the annuli, Well 43/21-2 is not expected to suffer corrosion-related perforation of both casing strings, at least within the next few centuries (i.e. corrosion rates of potentially <0.1mm/r for the 13 3/8" casing and << 0.1 mm/Yr for the 9 5/8" casing). Corrosion perforation through to the 9 5/8" casing bore could occur (assuming local communication paths through the cement) over very long time periods. Further corrosion (assuming that the plugs retain pressure integrity) would be limited by very slow diffusion between the completion fluid left in the well and the aquifer brine.

Provided that the 13 3/8" annular cement is adequate to prevent flow up the annuli, 43/21-3 is not expected to suffer corrosion-related perforation of the 9 5/8" casing until a century or more has passed (i.e. corrosion rates of <0.1 mm/yr). Corrosion perforation could occur (assuming local communication paths through the cement) over longer time periods. If the 9 5/8" annular cement is not adequate to prevent flow up the annuli, then the life of 43/21-2 is expected to be similar to that of 43/21-3.

Based on these data, it can be concluded that 43/21-2 is unlikely to suffer corrosion-related casing perforation giving rise to a brine leak for the duration of the over-pressure; however for 43/21-3 there remains a finite though low risk that brine might leak towards the tail end of the over-pressure if brine leaches through the 13 3/8" annular cement and corrodes the casing.

9.2 Brine Pressurisation Summary

Table 11 shows that maximum pressures which could be expected at the end of CO2 injection at the various well locations could range from 250 to 800 psi, which is enough to enable brine to flow to the seabed if there was a flow path. Isolation of the annulus corresponding to the hole section where the Bunter sandstone was drilled varies from long cemented intervals to uncemented annuli (but with adequate fracture gradient to the shoe above), with a number of wells having limited data available. Laterally extensive barriers are generally not present nor would be expected in these well designs and abandonments from the period, although there are no wells with direct brine leak paths to the seabed.

A semi-quantitative risk assessment is provided later in this document which attempts to assess this risk.

10 Halite Creep

The Bunter sandstone is overlain by the Rot clay and Rot halite. Based on clay type, experience indicates that the clay is not expected to swell over time; however the Rot Halite is expected to creep and provide further isolation.

The basis for this expectation is industry experience, academic models, published papers and direct indications from offset wells around Endurance. These topics will all be discussed in this section.

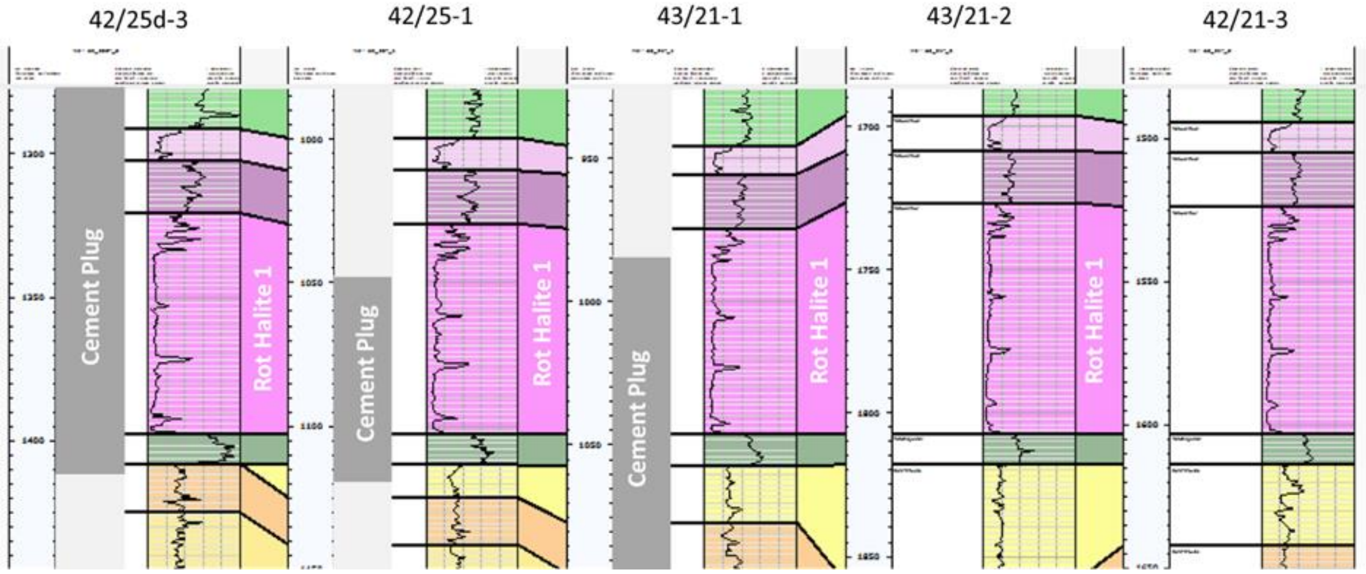


Figure 23 Seal and Cement Correlation (wells within the storage complex)

10.1 Offset Well Halite Creep

Although poor drilling practices can contribute to hole problems, the ubiquity of stuck pipe, tight hole and hole fill across close offset wells suggests drilling practices are unlikely to be the cause in all cases, indicating the creep process in both the Rot and Muschelkalk halites can start immediately:

- 43/21-3: Whilst drilling the Rot Halite with 1.34sg salt-saturated mud, frequent tight spots resulted in string stall and stuck pipe requiring jarring to free pipe and drill ahead. This is evidence of swelling of the wellbore / salt creep. The hole was vertical through the Rot Halite.
- 42/30-8: Precautionary reaming for salt creep in Rot Halite was reported.
- 42/30-6: Indications of Muschelkalk Halite swelling reported - tight hole requiring remediation (reamed from 1395 to 582m). Further remediation needed 2 days later.
- 42/25-1: This well did not report any major issues during drilling or running casing with salt saturated mud ranging from 1.2 to 1.32sg, although halites proved slightly mobile and back-reaming was needed POOH through the Rot and Mushelkalk halites

10.2 Published Papers

A 2017 paper[4] looked at Rot Halite creep in a series of offset wells as part of anther operator's abandonment program; a precis of the abstract is included here as a summary:

Recent ultrasonic cement evaluation logs, performed as part of the integrity diagnostics required for plug and abandonment operations, showed an increase in casing ovality when logging through a specific halite formation in the southern North Sea. These findings were used to postulate that the formation was coupled mechanically to the casing and could be used as an abandonment barrier. The circumferential cement evaluation data helped to identify the azimuthal coverage of the formation, and subsequent pressure testing confirmed the integrity of the halite formation as an isolating medium. Multiple offset wells were also analyzed with a focus on identifying additional horizons exhibiting mobility that could be detected using casing logging tools. It became evident that this halite formation showed a consistent and clear correlation between casing ovality and circumferential coverage. Case studies are presented in which the halite formation was identified as an appropriate barrier, based on the combined interpretation of both cement evaluation and casing inspection data. This phenomenon typically occurred when the top of cement was below the halite interval; however, in some cases, the formation movement actually improved the cement bond quality across the zone.

10.3 BP Halite Creep Modelling

BP commissioned an internal geomechanics report to evaluate the potential for Rot Halite (and the shallower Mushelkalk halite) to creep and seal the 12 ¼" open hole through the Bunter in 43/21-1, as an additional barrier should the primary cement plug be impaired or have slumped. This well was drilled and abandoned in 1970. As part of the study, a more general evaluation of the potential to creep against annular cement or against the outer wall of casing was also made, which aligned with the 2017 paper[4] and halite creep tests done on halite core from the 42/25d-3 appraisal well.

10.3.1 Rot Halite Creep – No Cement Present

In a case where no cement is present across the Rot Halite in 43/21-1 (e.g. primary plug has slumped completely). the analysis predicts that it will take 55 years for the 65m of Rot Halite to form an equivalent seal to 30m 0.01mD cement. Annular closure around a hypothetical 8.5" OD casing would only take 4.3 years. This is shown in Figure 24.

Where the cement Plug 1 covers the Rot Halite, any leak path on the cement to formation interface is expected to seal very quickly, although if the cement quality is very poor the stress applied by the halite may not be sufficient to improve the sealing capacity of the plug itself.

However, if the plug is not a reasonable seal it is likely that any halite above the plug will form a seal 55 years from abandonment, If only a very short section of halite was present above the plug it is expected that the likelihood of achieving a good seal would be reduced, but in this case the cement would be present and so would be proving a seal anyway.

[4] SPE-184720-MS. The Silver Lining to Squeezing Salts: Practical Cased Hole Logging and Interpretation Method Determines if Mobile Formations Act as Annular Barriers for Plug and Abandonment Applications, David Lavery and Andrew Imrie, Halliburton, 2017

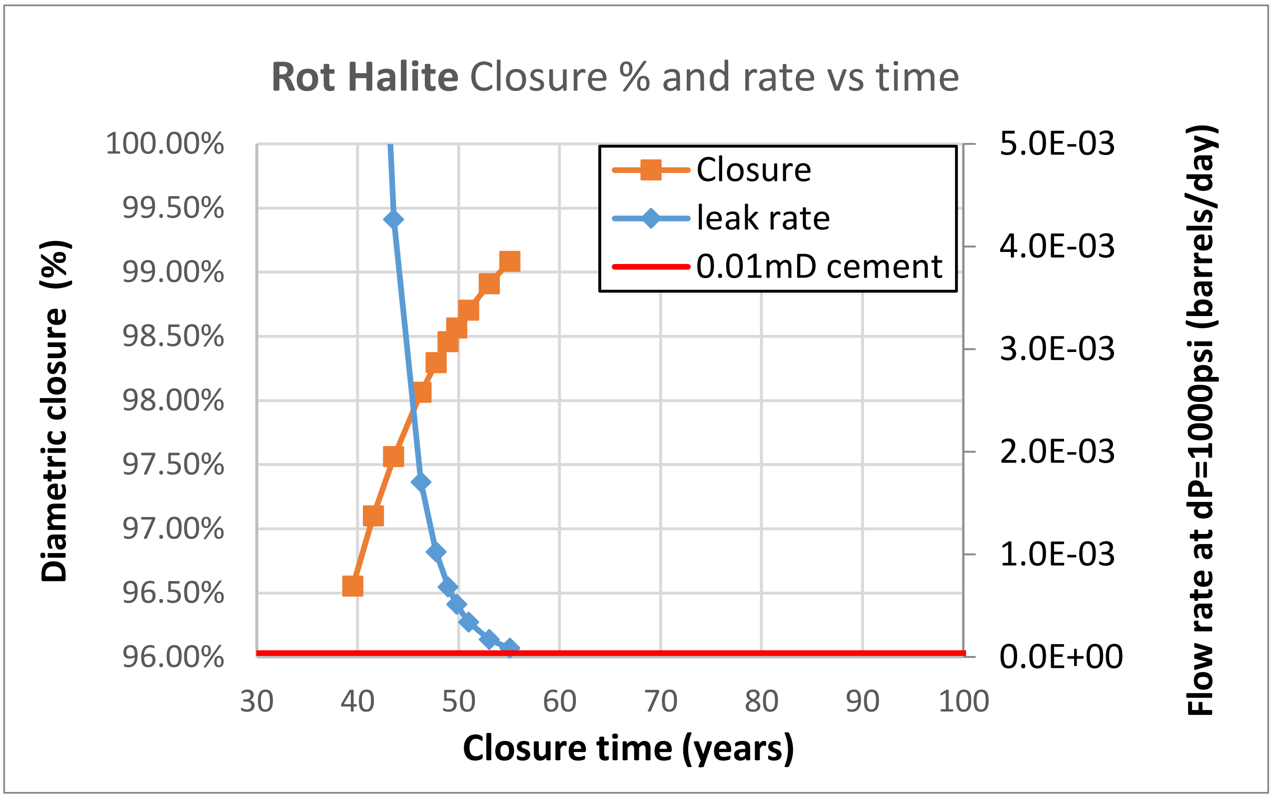


Figure 24 43/21-1 Leak Rates Relative to Cement Plug for 65m of Rot Halite at a Depth of 1000m

10.3.2 Muschelkalk Creep – No Cement Present

The Muschelkalk halite is approximately 65 or 66m thick, with its top at 813m MD, across abandonment plug 2. As such it cannot be classed as a barrier to CO2 because the formation fracture gradient below the plug is not sufficient to hold maximum reservoir pressure anyway.

That said, it is instructive to include the Muschelkalk analysis for information.

In a hypothetical case of a 12 ¼" open hole with no cement present (in reality not the case as Plug 2 was tagged), The analysis predicts it would take 123 years for 65m of Muschelkalk Halite to form an equivalent seal to 30m 0.01mD cement. Annular closure around a hypothetical 8.5" OD casing would only take 9.6 years. This is shown in Figure 25.

While a seal in the Mushelkalk is not expected to develop until after the end of planned operation of the store it does impact the possible initiation and propagation of a fracture at the base of plug 2.

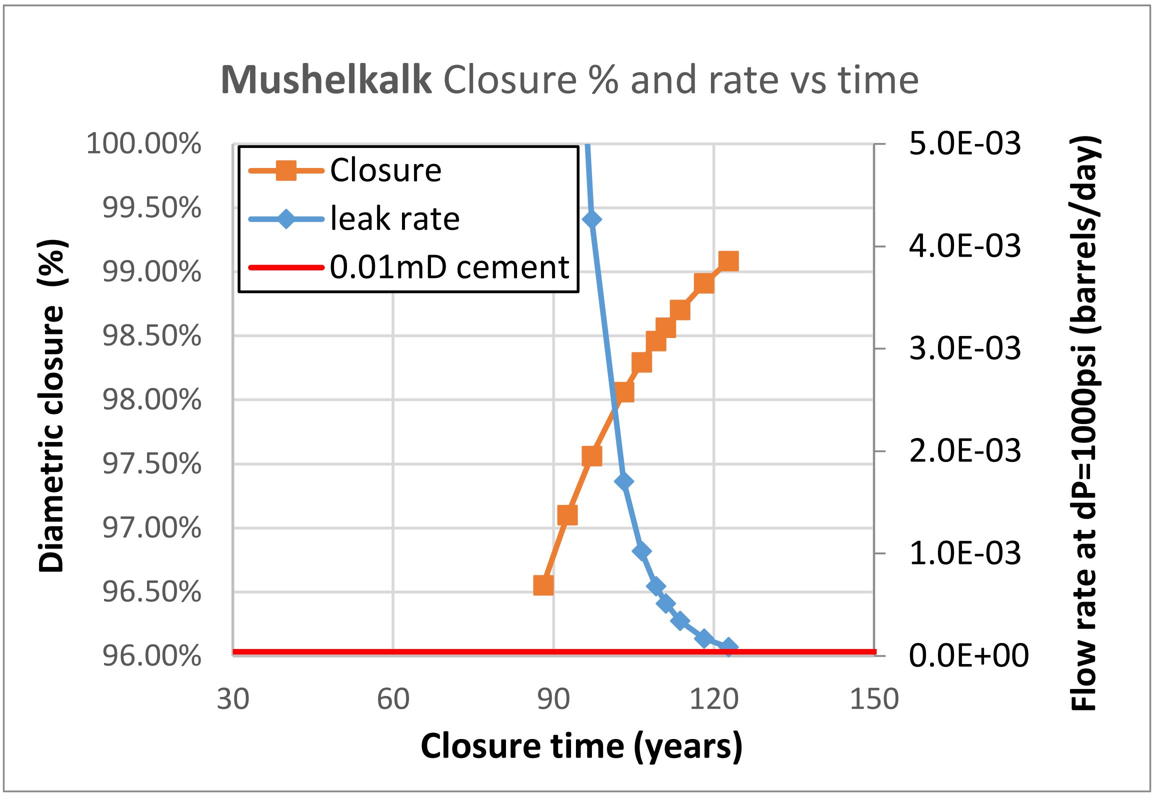


Figure 25 43/21-1 Leak Rates Relative to Cement Plug for 65m of Mushelkalk at a Depth of 800m

10.3.3 Halite Seal Development over Time

Alternative perspectives on the development of both the Rot Halite and Muschelkalk halite seals over time are presented in Figure 27 and Figure 28, with an estimate of effective permeability of the Rot Halite shown in Table 12.

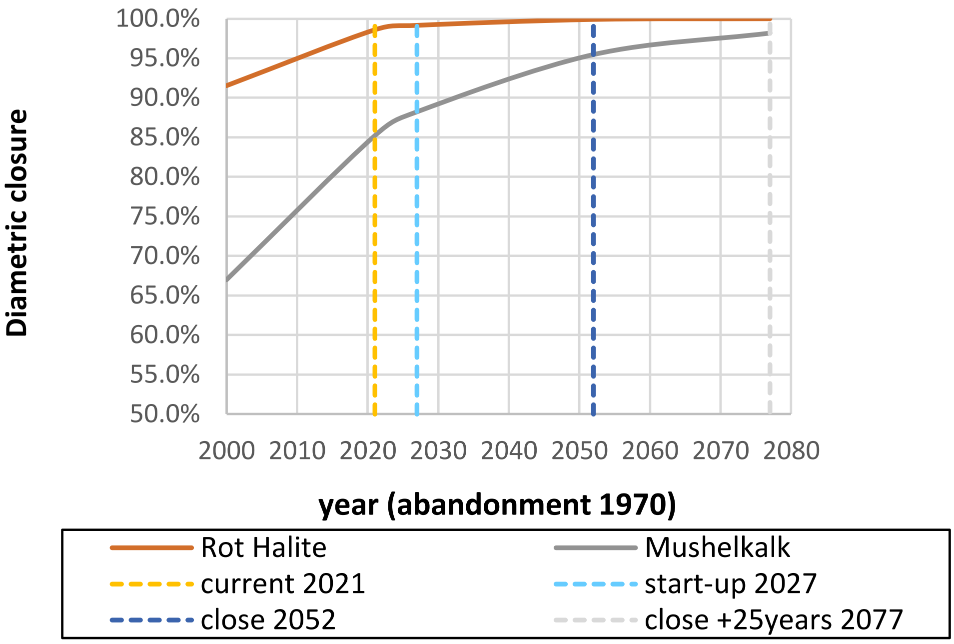


Figure 26 43/21-1 Halite Closure % vs. Time

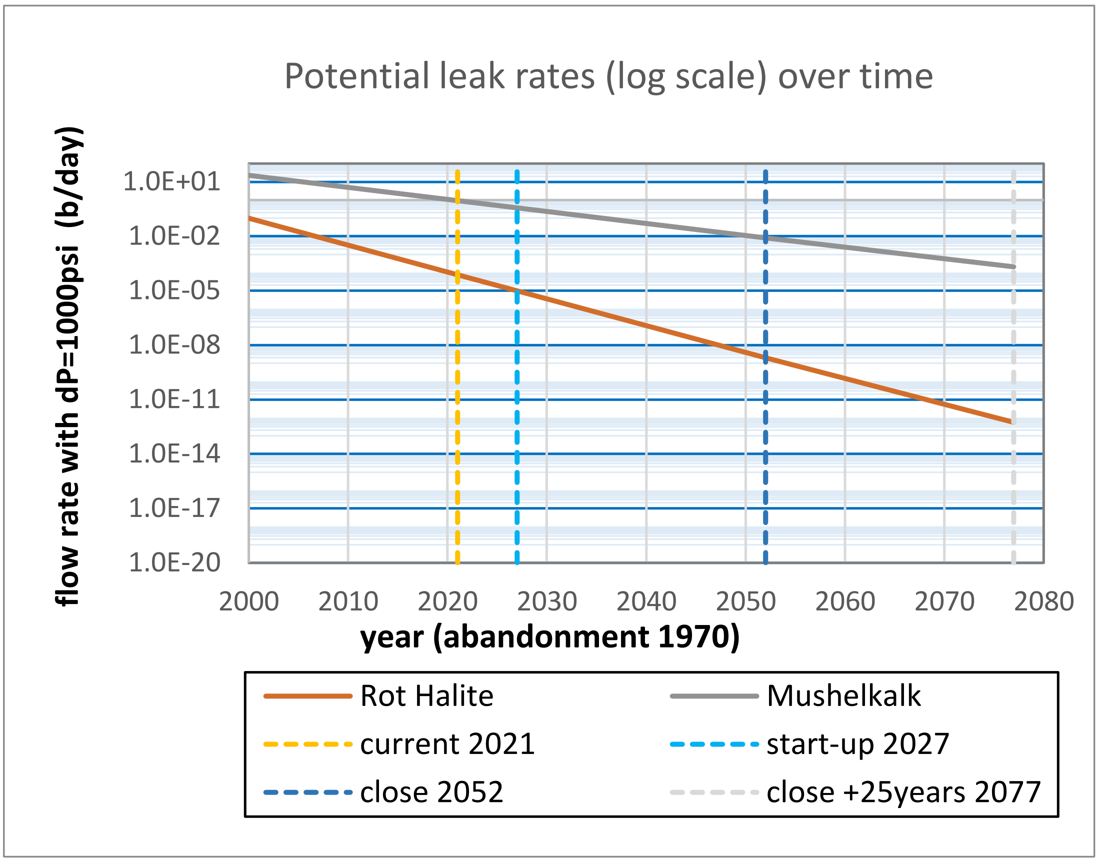


Figure 27 43/21-1 Estimated Potential Leak Rate over Time

65m Halite seal equivalence to a 30m cement plug (at dP=1000psi)			
year	cement perm mD	flow rate barrels/year	note
2021	7.22E+01	3.57E+01	
2027	5.63E-02	2.78E-02	< design
2052	7.28E-03	3.60E-03	< design
2077	1.45E-06	7.18E-07	< design
design	1.00E-02	8.52E-05	

Table 12 43/21-1 Rot Halite – Cement Equivalence in Sealing Capacity vs. Time

10.3.4 Rot Halite Closure Time vs. Exposed Halite Length

The length of halite seal above the cement plug 1 is uncertain; this plug may have slumped when placed. The quality of the cement below the halite seal may also be poor if mixed with the drilling mud (high effective perm), if it were to contain large channels the effectiveness of the plug as a seal may not be improved by stress applied by halite creep in the overlap between halite and cement. In this case sealing of the wellbore would be more reliant on the closure of the halite section above the plug. To assess this the time to develop a halite seal, equivalent to a good 30m 0.01mD cement plug for the expected range of possible lengths of halite above the plug is considered.

Note that for any length of exposed Rot Halite less than its full thickness of ~65m means that plug 1 cement extends above the Bunter, through the Rot Clay and into the Rot Halite, indicating that the plug is present.

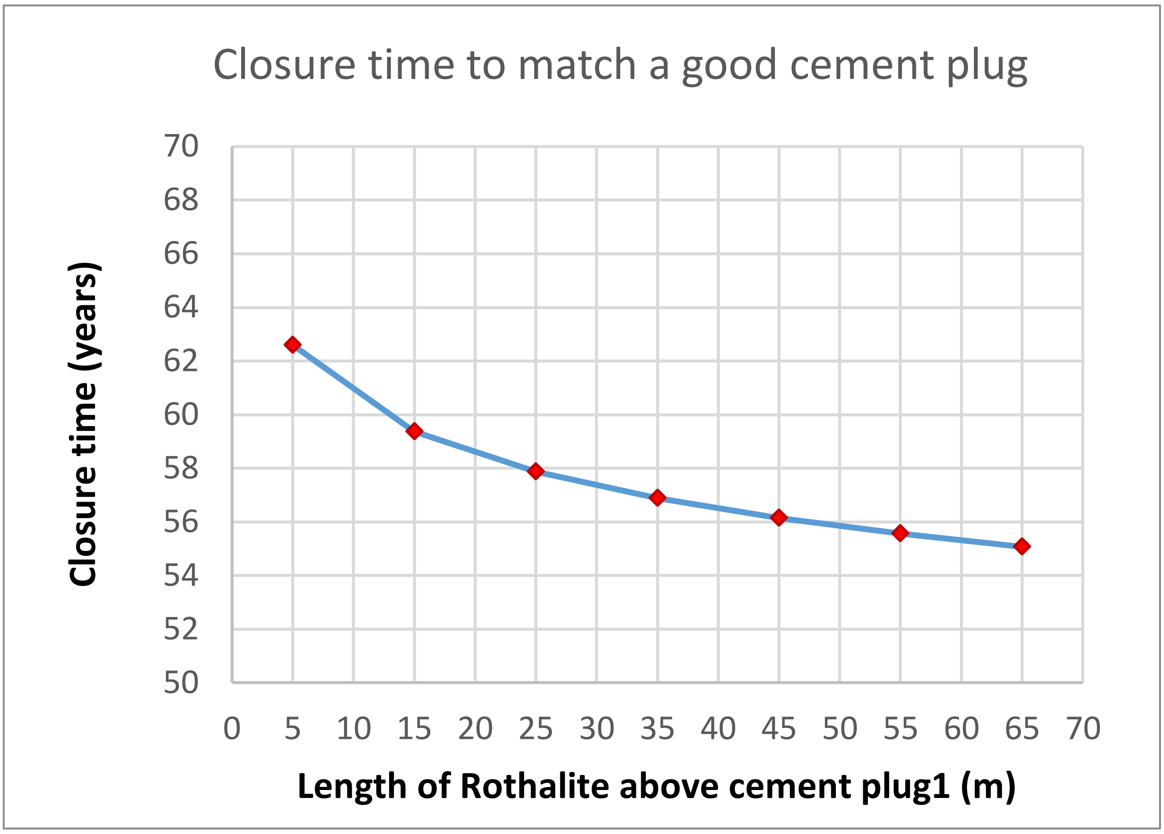


Figure 28 43/21-1 Estimated Rot Halite Closure Time vs. Exposed Length

10.4 Hydraulic Lock and Effect on Bunter Isolation

It is considered possible that the pressure developed by volume displacement due to creep in the Rot and Muschelkalk halites in the 12.25" OH could have reached the fracture pressure at the base of cement plug-2 soon after abandonment, assuming no leak-off to the formation. The fracture would only grow at the rate of net volume displacement (creep – any leak-off). Approximate estimates indicate that a fracture is unlikely to grow above cement plug 3.

As ~98% of the volume displacement is predicted to take place before 2020, the full extent of fracturing is expected to have taken place by now.

Note that this calculation extends to a seal of less than 5m in length, uncertainty in the consistency of radial creep is expected to increase as the length considered decreases.

For well 43/21-1 specifically, this allows some logic to be applied to gain confidence that the Bunter is isolated:

- If there is hydraulic lock (fluid between upper and lower plugs) that could not leak off and prevented the Rot Halite from moving, then primary plug 1 must be a seal across the Bunter because otherwise the fluid would leak away into the Bunter sandstone.

- If primary cement plug 1 is not present or had slumped to expose the permeable Bunter, then the halite will be allowed to move as fluid can leak off into the Bunter, thereby sealing the borehole above the Bunter and re-instating the cap rock.
- If primary cement plug 1 is indeed intact and halite creep can create enough pressure, the formation will fracture below the upper plug and fluid will leak away (expected case - see above), allowing the halite to close in and re-instate the cap rock in addition to a sealing lower primary plug.
- If there are defects in the primary plug that expose the Bunter, the Rot Halite should still close in as fluid can leak away through the defects, thereby sealing them.
- If the halite creep causes damage to primary plug 1, then this indicates the halite is mobile and will seal the well above plug.

Therefore, there is confidence that as a minimum, the Bunter will be sealed in 43/21-1 by either the primary cement plug or the Rot Halite.

This data and logic have been used in the semi-quantitative leakage risk assessment presented later in this document.

10.5 43/21-1 - Risk of Wellbore Breakout on Halite Creep Rate

The fluid density above the lowermost plug across the Dowsing shale (plug 1) was 1.21 SG (10.1 ppg). Modelling suggests that if this fluid were to degrade, stratify or leak-off and equalise with Bunter brine pore pressure (1.09 SG), then there would be the potential for borehole breakout and creation of cavings.

Such cavings could then fill up the open hole and potentially impact halite creep and sealing capability.

The cause of such a scenario developing would be if plug 1 was not sealing - either because it had “slumped” below the Bunter or had not bonded with the formation and had developed a micro-annulus, creating a hydraulic path to the Bunter sandstone.

The fluid across the Dowsing (above plug 1) could then leak-off into the Bunter, resulting in a uniform 1.09 SG fluid in the open hole section below the 9 5/8” casing, or some intermediate density in between.

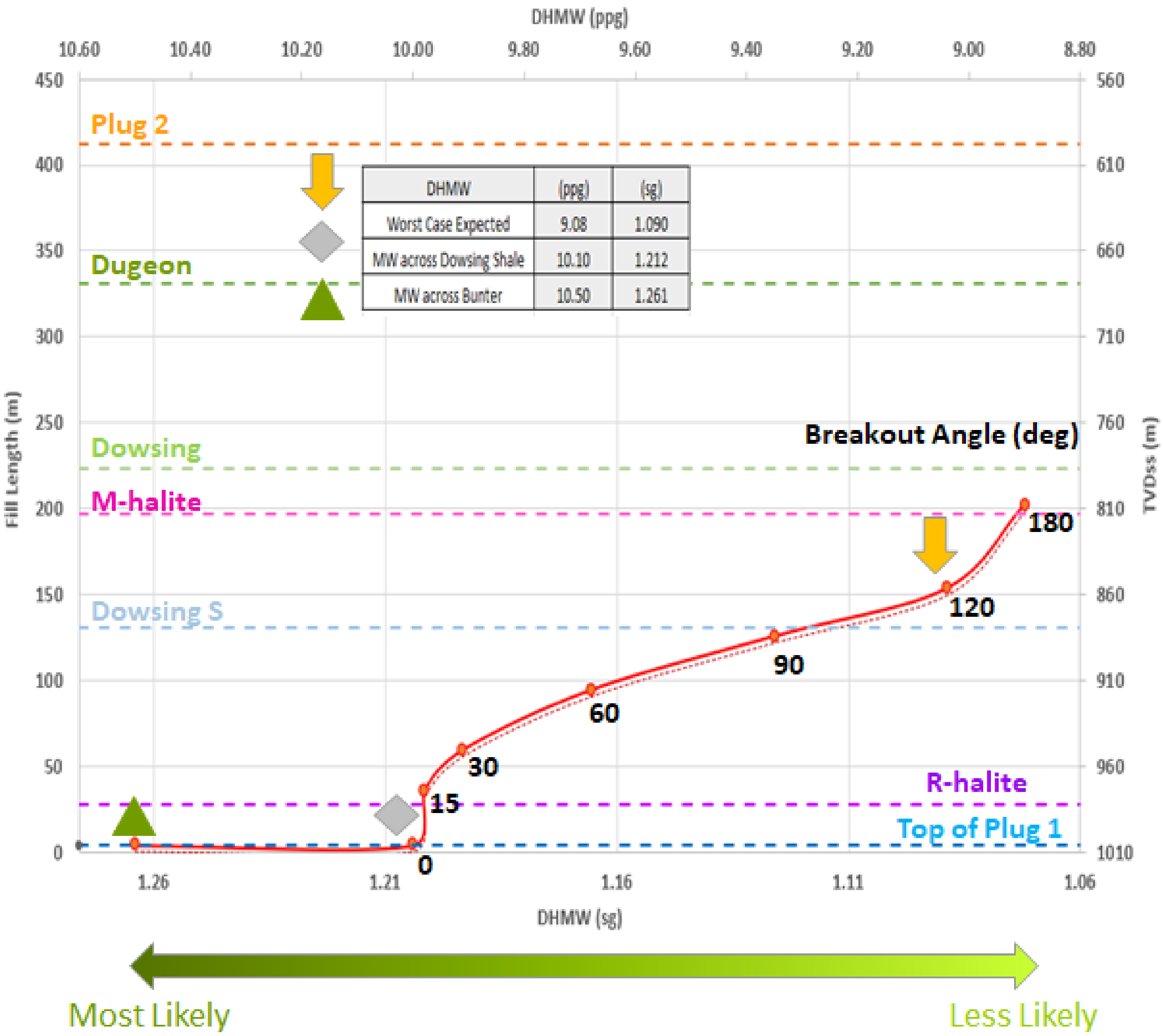
The height of any fill is determined by the bulk volume of cavings generated and the size of hole being filled. The volume of cavings is estimated from the hole enlargement averaged over the thickness of the unstable formation multiplied by this thickness (length of interval). A bulking factor is applied to take account of the fact that the volume of cavings is greater than the original volume of intact rock.

10.5.1 Breakout Angle and Reduction in Fluid Density

Figure 29 shows the estimate of top of cavings breakout fill above plug 1 for various mud weight reduction scenarios. Figure 30 and Figure 31 are repeated from earlier in this document to help visualise the situation.

- Worst case break out angle is ~120 deg for a 1.09 SG fully-equalised fluid density
- Worst case top-of- fill is shown at ~860m TVDSS, some 150m above plug 1 and ~20m above the Rot Halite

- A MW reduction to ~1.11 SG (9.3 ppg) would equate to an estimated fill to the top of the Rot Halite
- If plug 1 had slumped to TD, then even if worst case break-out did occur, the top of fill would still be below the base of the Rot Halite
- These estimates all assume a bulking factor of 1.1 (vol occupied by fill / vol of breakout material)



DHMW	(ppg)	(sg)
Worst Case Expected	9.08	1.090
MW across Dowsing Shale	10.10	1.212
MW across Bunter	10.50	1.261

Figure 29 43/21-1 Shale Fill Top vs. Downhole Fluid Density

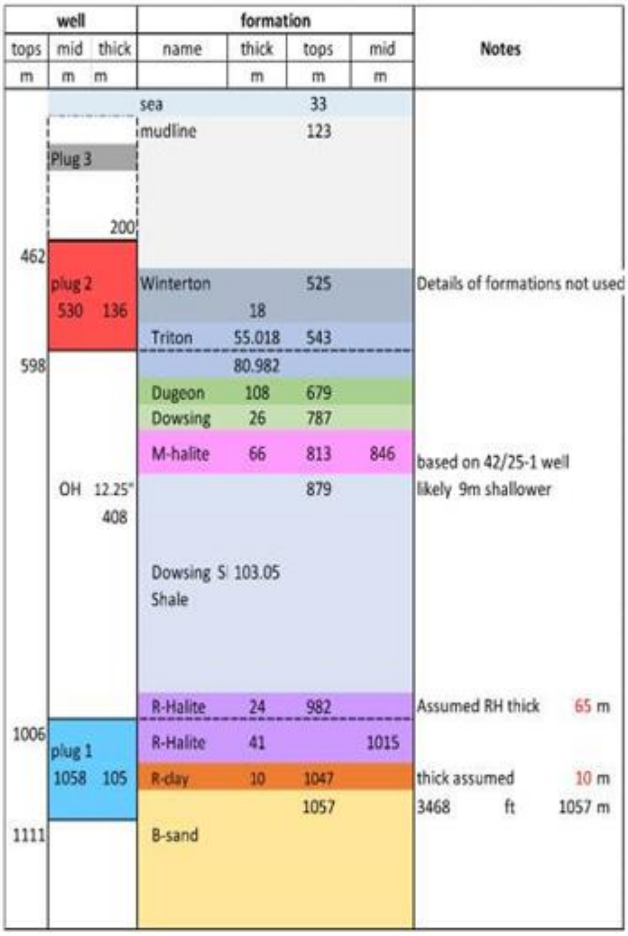


Figure 30 43/21-1 Stratigraphy

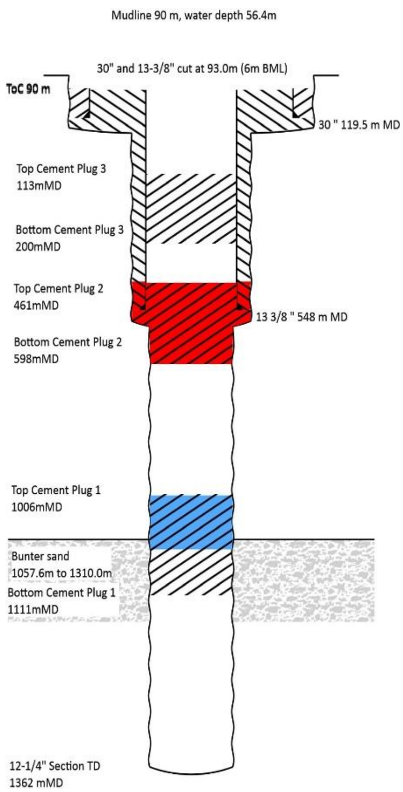


Figure 31 43/21-1 Abandonment Schematic

10.5.2 Sensitivity on Bulking Factor

It is unlikely that stratification of the abandonment fluid would occur, only a full equalisation to Bunter pore pressure (1.09sg). Sensitivities were therefore made assuming a fully equalized fluid, calculating fill height vs. bulking factor and hole enlargement:

- Fully equalized fluid was assumed
- The full Dowsing Shale interval is assumed to become unstable.
- The well below Top Rot-Halite is assumed to be in gauge (conservative if actually is enlarged)
- The average hole enlargement is assumed in sections of the unstable well that are filled

Estimates of fill height were made for

- Variations in assumed bulking factor, range 1.1 to 1.6
- Variations in assumed average hole enlargement (hole enlargement of 100% implies gauge hole)

Three cases were evaluated for residual uncertainty in the position of Plug 1:

1. Top of cement plug at expected depth ~24m below Top Rot-Halite
2. Top cement slumped to just below Top Bunter ~75m below Top Rot-Halite
3. Top cement slumped to TD (no cement plug) ~380m below Top Rot-Halite

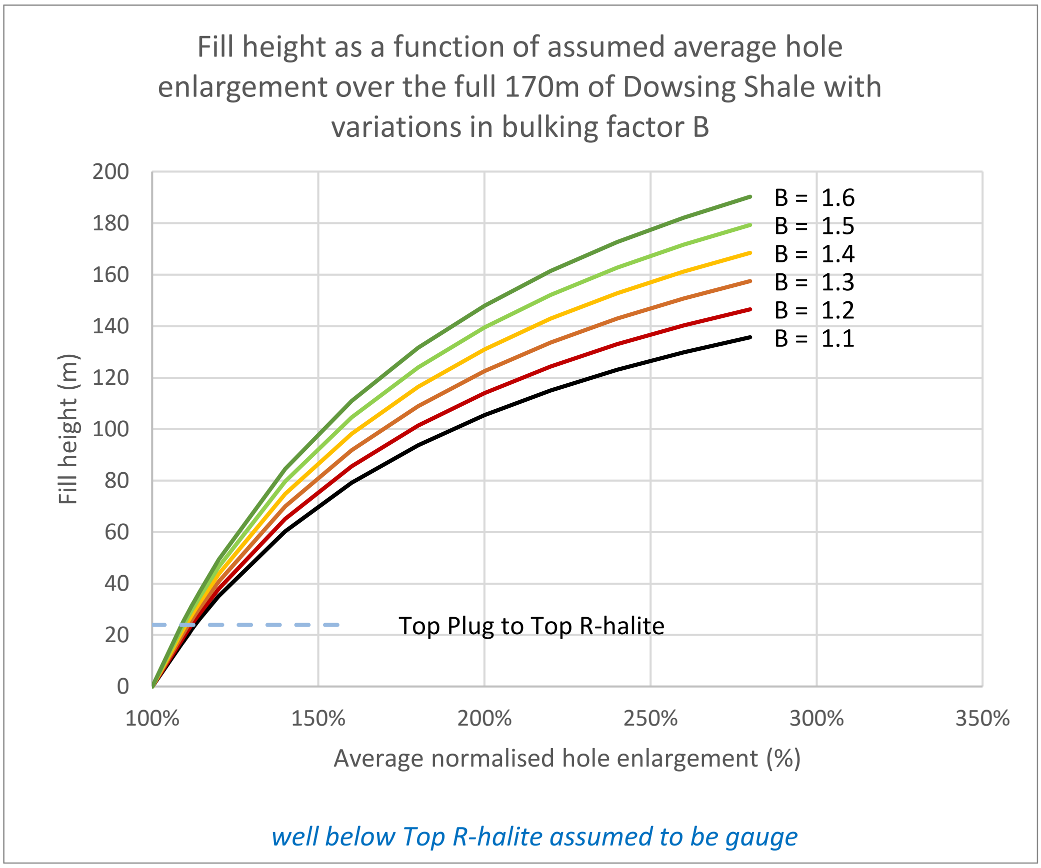


Figure 32 Top of cement plug 1 at expected depth ~24m below top Rot-Halite

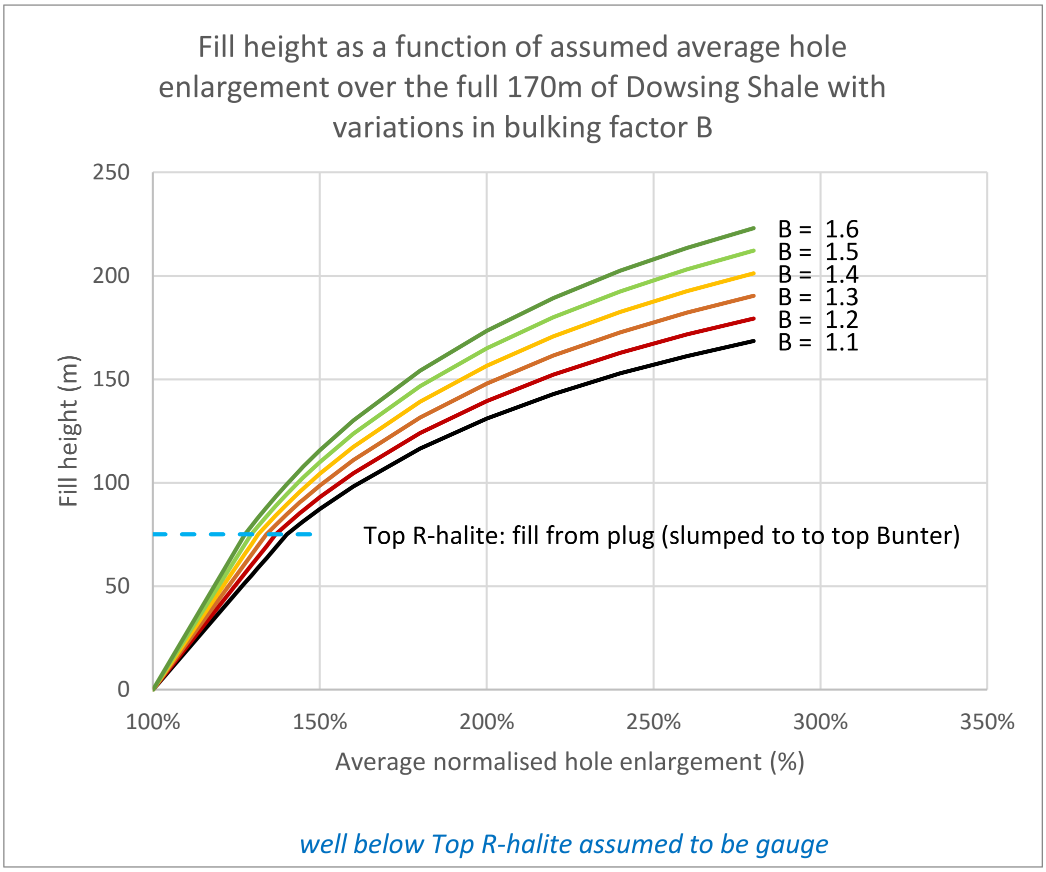


Figure 33 Top cement slumped to just below top Bunter ~75m below Top Rot-Halite

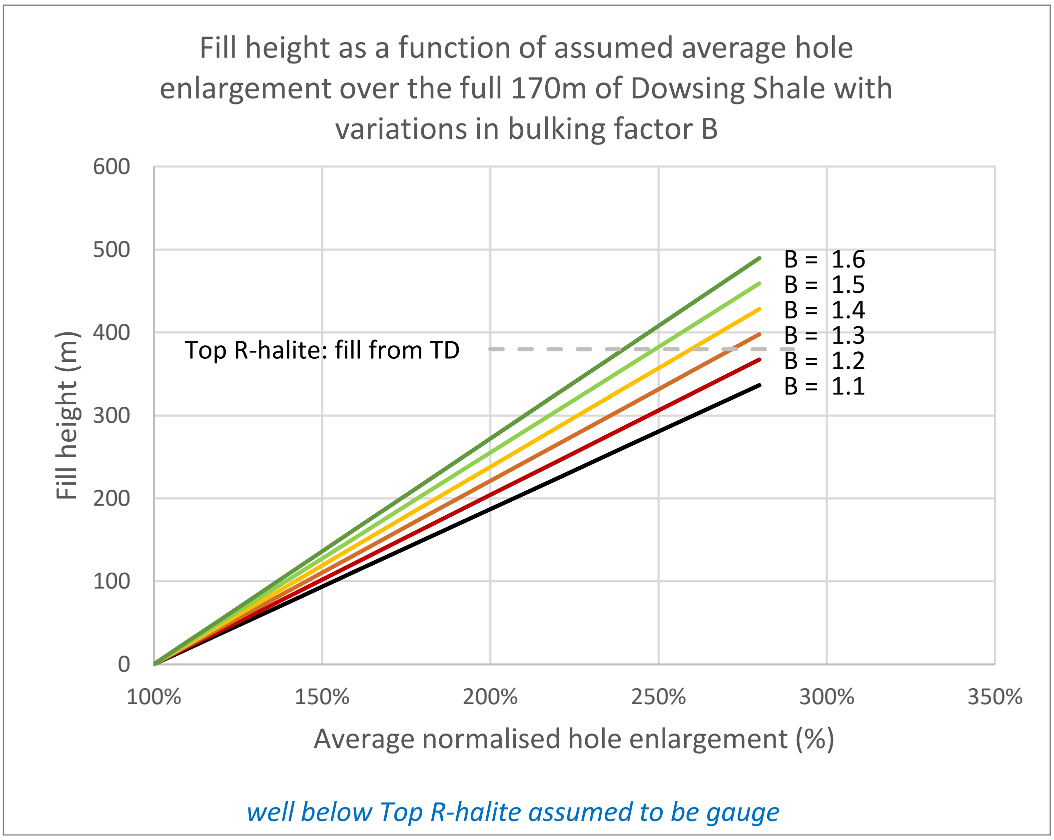


Figure 34 Top cement slumped to TD (no cement plug) ~380m below top Rot-Halite

10.5.3 Discussion

Although the modelling suggests that breakout is possible, the likelihood of it happening and the impact of it subsequently on the ability of the Rot Halite to creep and eventually seal warrants further discussion:

- The fluid density needs to reduce to 1.2 SG (10 ppg) before any breakout is induced – density stratification or segregation is not expected to occur with the fluids left in the well in the timescale for the majority of the halite creep to have occurred; e.g. the last ~4% of creep to create an equivalent seal takes ~20 years (extrapolated from Figure 24)
- Significant to worst case density reduction relies on a leak path at plug 1. Such a pathway is likely to be sealed by halite creep if the top of the plug is above the Rot Clay top, even if the plug did not seal very well initially. This is likely to take place quite quickly (possibly in order of months, if not weeks, depending on channel size and geometry).
- If fill extends above the Rot Halite before it closes enough for the fill to sit on top of the crept halite "bridge", then the formation of the salt seal may depend on the nature of the cavings trapped within it as it moves. If the cavings are soft ("gumbo-like"), the sealing may actually occur sooner as the soft clay compacts to low permeability, but it is unlikely to be any longer than predicted for no cavings fill.
- Although offset wells 43/21-3 drilled in 1994 and 42/25-2 drilled in 1995 had indications of such Gumbo forming, it is likely that this was due to the use of water-based muds, and it is more likely that the Dowsing shale cavings are more brittle or "gravel-like". In this case, the salt forms a "mélange" with the gravel as the salt creeps between the cavings, and behavior is more complex and difficult to predict. The time for halite creep to seal could be longer, or the gravel could lead to conductive pathways that take longer to form an equivalent seal of 30m of good cement. Conversely the presence of gravel may reduce the volume to fill and so lead to minimal impact on the creeping and sealing process.
- The key input parameters to the fill volume (and hence fill height) model are the hole length and enlargement area due to breakout (i.e. does breakout affect the whole length of the Dowsing, and how much material falls in radially to enlarge the hole diameter), and the bulking factor (i.e. the settled cavings volume in pieces compared to all compacted together when intact). Although a bulking factor of 1.1 may reflect a more "gumbo-like" behaviour rather than "gravel like" cavings, the modelling has assumed that all of the Dowsing shale is affected by breakout with a significant hole enlargement and so is inherently conservative and is likely to predict a greater volume of cavings than would be seen in reality. This was the reason for evaluating sensitivities in bulking factor.
- For shale cavings fill to inhibit a barrier forming due to salt creep the fill would need to have been generated soon after abandoning the well. As the salt barrier starts to form the hole size through the Rot-Halite will reduce and if small enough at the point where cavings start to be generated, the cavings are likely to bridge the remaining channel through the salt and hence have little impact on barrier formation.

10.5.4 Wellbore Breakout - Conclusion

In all of the scenarios evaluated there is some chance that that shale cavings will fill the well across the Rot Halite if a reduction in fluid density were to occur.

For Plug 1 located at or above the top of the Bunter, cavings fill across the halite is considered very likely as relatively little average hole enlargement in the shale needed, even with a low bulking factor assumption. However, if Plug 1 is in this position, it is much less likely that any reduction in fluid density would occur to generate cavings in the first place.

If Plug 1 has is defective or has slumped further down the well, fill is unlikely to cover the Rot Halite as this would require significant hole enlargement (>225%) with a high bulking factor.

Overall, it is considered unlikely for all the worst case conditions to be met for halite creep to be impacted significantly beyond the creep predictions detailed in Section 10. Residual uncertainty is allowed for in the risk of halite not sealing of 7.5% as used in the semi-quantitative leak rate modelling described in the next Sections.

11 Remedial Well Operations

As all of the legacy wells have had their surface casing strings and wellheads removed as part of their abandonment programmes; any remedial operations will involve either relief-well techniques or potentially building a coffer dam around the well location so that the conductor and casing stubs can be excavated prior to reconnecting to the well (direct intervention).

Although these sorts of remedial well re-entries have been done many times in the industry over the years, the challenge of re-entering and sealing wells that are 50 or more years old should not be underestimated.

The key challenge is actually entering the old hole to plug the source of the leak, rather than the mechanical and logistical operations themselves; for example, the presence of multiple cement plugs could cause sidetracks to be kicked-off, and re-entering an old open hole section below casing that has been plugged will make kicking-off even more likely, thereby simply creating a new hole.

Furthermore, and perhaps most importantly, re-entering a well (open hole) will drill through the halite that has crept to form a seal over the years, possibly making the situation worse.

Therefore it is recommended that legacy well re-entry operations are not undertaken pre-emptively.

As part of the store permit application to the regulator, a Corrective Measures plan will be developed which will include a detailed plan for remedial well operations, in the remote chance they be required.

12 Preliminary Qualitative and Semi-Quantitative Risk Assessment

Risktec were commissioned to carry out both a qualitative and a semi-quantitative risk assessment[5] for legacy wells on and off-structure, using a similar approach to other CCUS developments particularly in Europe. This section presents a precis of this report using 43/21-1 as an example well.

The semi-quantitative assessment was conducted assuming infinite formation deliverability (PI) and an equivalent-permeability model for channels and large leak paths which is inherently conservative.

To address these limitations, a more detailed fine-grid model was commissioned from Heriot Watt University (HWU), using a modelling approach described in the literature[6]. Full results from this study were not available at the time of writing; nevertheless a summary of available results is presented in Section 13.

12.1 Summary

A qualitative bowtie assessment was performed to identify potential leak paths from the wells and to assess the quality of the barriers within each leak path. Based on the bowtie barriers, a semi-quantified leakage risk assessment was developed for each well where information existed.

The risk assessment has identified a number of discrete leak paths and has analysed all of them for their probability of occurrence and expected mass of CO2 or brine released per year. Each leak path considered the individual barriers present, the probability that the barrier would be intact, impaired or failed, and the leakage rate (CO2 or brine) that may result.

The assessment indicates that the expected release rates of CO2 from on- and off-structure wells with intact barriers are very low – fundamentally determined by the intact finite permeability of that barrier material. Should a barrier be compromised, then a range of release rates may result, although the probability of a major leak path existing is remote. The acceptability of any magnitude of CO2 release is not for this report to determine.

The injection of CO2 into the Endurance structure will also result in an increase in brine pressure within the reservoir and a displacement of brine into the wider regional aquifer. The analysis has therefore considered the potential for brine to be released from off-structure wells.

For both brine and CO2 release cases, the potential release rates will decrease after injection ceases as the pressure within the reservoir declines, dependent on aquifer connectivity regionally.

It must be stressed that this numerical risk calculation is based on the best estimates of experienced personnel, together with academic and industry published data. Given the fact that the legacy wells are not accessible for any barrier testing, the results should still be considered approximations, further limited by assuming infinite formation deliverability (PI) and an equivalent-permeability model for channels and large leak paths which is inherently conservative.

As mentioned above, a more detailed fine-grid model was commissioned from Heriot Watt University (HWU), to address some of the conservatism using a modelling approach described in the literature[6], but only an outline summary is available at the time of writing; presented in Section 13.

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[5] BPX-44-R-02 Issue 2.0 Endurance CO2 Storage – Legacy Wells Leakage Risk Assessment, Risktec, 28th April 2022

[6] SPE-200608-MS, Application of Numerical Flow Simulation Methods to Risk-Based Well Decommissioning Design, Caroline Johnson, Morteza Haghighat Sefat, and David Davies, Heriot-Watt University, 2020.

12.2 Risk Assessment for 43/21-1

An initial set of leak paths was created for each legacy well. This section uses the on-structure 43/21-1 well as an example shown in Figure 35, but the complete set of individual well leak paths can be found in the Risktec report[5]. The leak paths were developed based on available information mostly from the NSTA NDR database for UK wells, with additional data from Operators where available.

- Drilling End of Well Report (EOWR)
- Geological EOWR
- Daily Drilling Reports
- Cementing Reports
- Plugging and Abandonment (P&A) diagrams and reports

The set of leak paths were intended to cover all credible discreet outcomes; where different paths could lead to the same outcome, the assessment concentrated on those paths containing the fewest number of well components on the assumption that these would have the highest overall probability of failure.

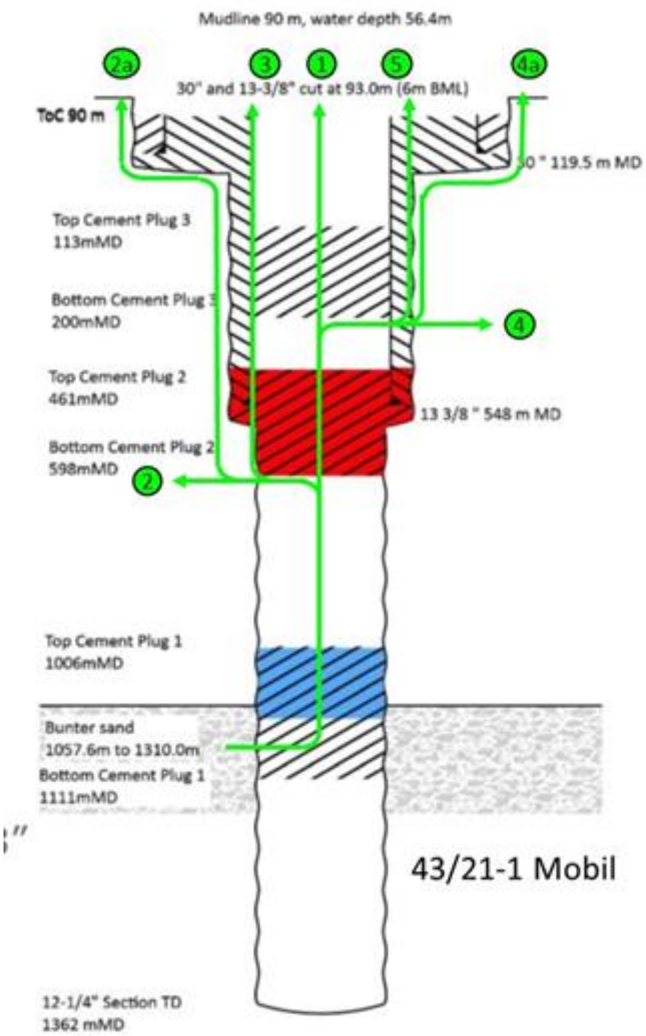


Figure 35 43/21-1 Leak Path Definition

12.2.1 Bow Tie Construction

For each confirmed leak path, the workshop team considered the quality of the barriers to prevent the flow of CO_2 from the reservoir, making estimations of the following parameters:

- Intact Permeability – the best estimate of the current status
- Impaired Permeability – should the barrier be of poor quality
- Degraded or failed Permeability - should the barrier fail
- Reliability – the probability that the barrier will be in a particular state
- Certainty – the certainty of the information recorded.

Figure 36 shows the bow tie diagram constructed for 43/21-1. The complete set of individual well bow-ties can be found in the Risktec report[5].

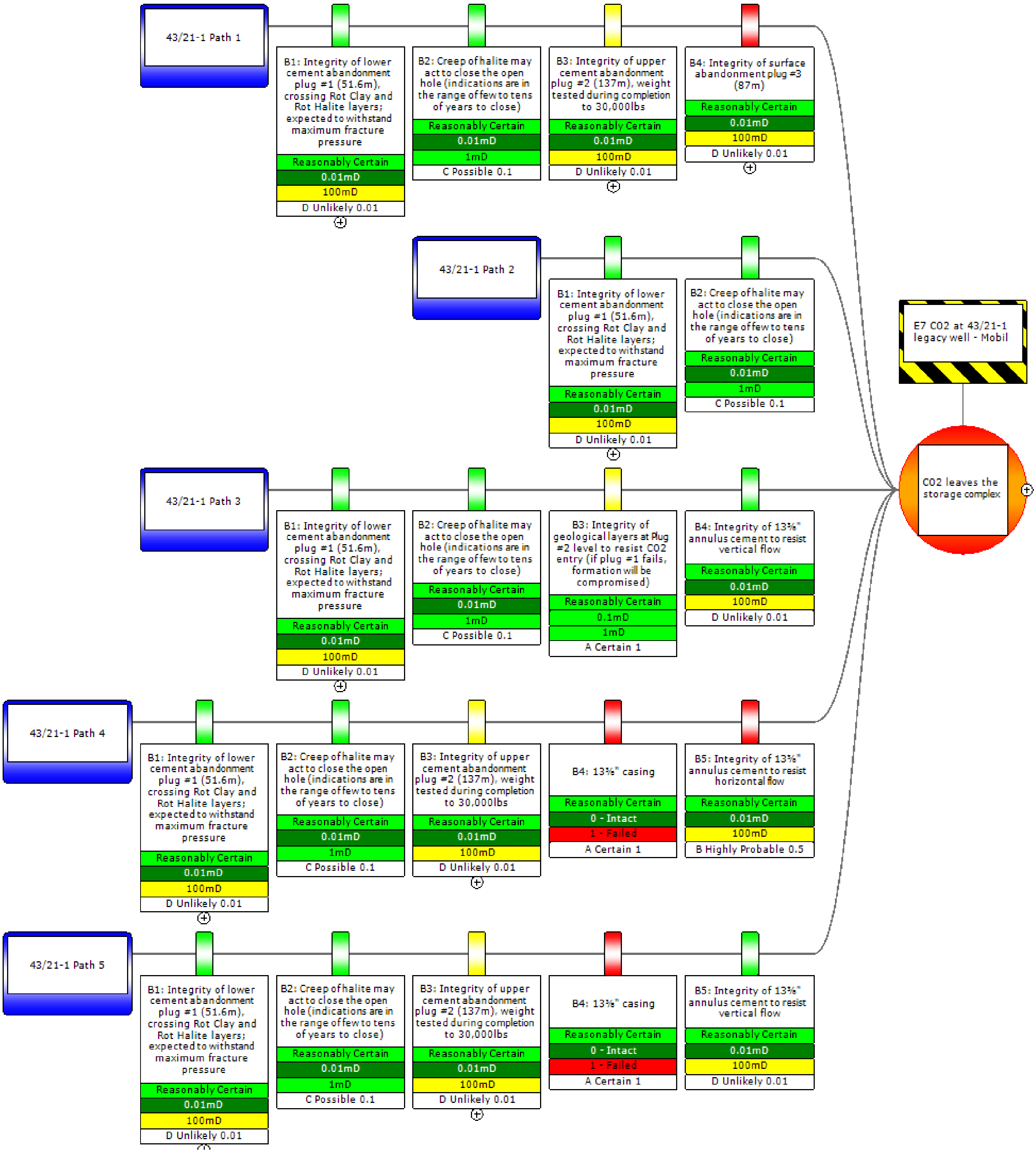


Figure 36 Bow Tie for 43/21-1

12.2.2 Barrier State Probability Estimation

Table 13 shows the probabilities assigned to each barrier state in the QRA. The data has been assimilated from many sources, academic and industry, with key points of note shown below.

A full list of sources can be found in the Risktec report[5].

Item	Intact	Impaired	Failed	Notes
Cement plugs	0.9999	0.01	1E-4	Where concern identified about a particular item, impaired and/or failed values increased (e.g. 43/21-1)
Annular cement	0.9999	0.01	1E-4	As above
Casing (CO_2)	0.01	-	0.99	Item is either intact or failed. For wells potentially exposed to CO_2, higher corrosion rates are conservatively assumed
Halite Creep	0.925	0.075	1E-4	'Intact' taken as halite creep occurring and closing annular space and/or wellbore
CO_2 retained within structure	0.997	-	0.003	Term is used to account for probability that reservoir management plan fails and CO_2 is allowed to extend beyond the spill point to reach neighbouring wells, e.g. 43/21-2. This is regarded as very pessimistic and may be revised
Brine-exposed casing corrosion	Prob (corrode in <25 years – 1e-4) Prob (corrode in 25-50 years – 0.05) Prob (corrode in 50-100 years – 0.25) Prob (corrode in 100-300 years – 0.5) Prob (corrode in >300 years – 0.75)			Corrosion rate expected to be low with just brine present as no free oxygen. 75%-25% view taken based on casing corrosion work in Section 9.1

Table 13 Probability of Barrier State

- Probability of impaired barrier 1% - Reference BP historical data for cement plugs placed and tagged at depth but failing pressure test/inflow test (2015-2019)
- Probability of failed plug - very unlikely that a continuous channel throughout the entire cement column will occur in a vertical well with low viscosity, low density mud. This assumption does not apply to annular cement, nor where the PPFG is insufficient
- Probability of failed annular cement more likely than a plug, but still unlikely in a vertical well with low viscosity, low density mud.
- Combination barrier should count as two plugs in series
- On halite generally, the probability of halite sealing approaches 100% - it's an asymptotic curve so never seals completely, but as soon as the faces "touch" we get the seal. Although the halite creep report suggests ~98.5% closure at the time of startup for 43/21-1, this is not quite the same as the chance of being intact. Nevertheless it is reasonable to assume 92.5% intact with 0.01mD perm as per intact cement.
- For 42/25-1, the halite will not have crept fully by the time of injection start-up in 2026/27, as it was only drilled in 1990; i.e. ~15 years short of the ~50 years to achieve 0.01mD. Modelling this could be achieved by making the halite "impaired" on this well until 2045. This has not been done in this version of the report.

12.2.3 Barrier Permeability Estimation

Permeability estimates were made for cement and halite based on published literature. Note that this implies that as the permeability of a barrier is finite, there will always be some flow through that barrier, no matter how infinitesimally small. It is important to realise that this is fundamental to the QRA presented in this report – at no point is a cement or halite barrier assumed to have zero permeability and therefore zero flow.

Casing is assumed to have zero permeability when intact, and a suitably large permeability when failed (corroded) to present no barrier to flow. Casing does not have an "impaired" state.

Cement

Intact	0.01 mD, based on cement permeability measurements.
Impaired	100 mD, assuming a continuous 30 micron micro annulus.
Failed	100 Darcies, assuming a continuous 5 mm channel, depending on tortuosity

Halite

Intact	0.01 mD. Halite creep calculations are based on the time to match an intact cement plug permeability, so halite also uses 0.01mD which is likely to be conservative over time.
Impaired	1 mD. This is a very conservative estimation based on the halite creep report. In reality, the "impaired" permeability is likely to be significantly lower than this, but 1mD has been chosen to force a difference between the two states.
Failed	The halite is expected to creep. No allowance has been made for it not being present or failing in a similar manner to cement.

12.2.4 Barrier Performance Calculation

Calculations are based on Darcy's flow equations adapted to flow through cemented annular and cemented pipe[7].

Assumptions

- Length of cement or halite from the well schematic or data records
- Delta P across the barrier 200-800 psi depending on reservoir pressurisation with time
- Viscosity of brine (2 cP)
- Viscosity of CO2 (0.05 cP)
- Reservoir deliverability (PI) is not considered in the maximum CO2 leak rates – therefore the analysis is conservative

Flow calculations were made for each barrier in each well for input into the probability event trees. The barrier performance for 43/21-1 is shown below in Table 14.

The method adopted for the leakage risk assessment uses an event tree approach to examine the potential for the leak path barriers to be either intact, impaired or failed and the various combinations that might exist.

For each path through the event tree, the maximum flow rate that may occur is then given by the lowest flow rate for any barrier within that path i.e. the CO2 or brine flow is 'choked' by the 'best' performing barrier.

Figure 37 shows the event tree structure developed for 43/21-1 leak path 1, showing the barriers in place, the probability of failure and the associated leak rate (shown in blue). To manage the total number of scenarios developed, it was assumed that the first barrier in the well (generally cement

[7] Well Cementing 2nd Edition , Erick B. Nelson and Dominique Guillot, Chapter 1

plug #1 in this case) would be the dominant choke point if it was intact, and hence this branch was not developed further, although for brine flow paths in off-structure wells, this was not always the case and the event trees were fully expanded all branches.

Each event tree path represents the probability that a combination of barrier states exists, representing a specific leak path with a commensurate flow rate. For this issue of the report, for a given reservoir pressure, both the probability and flow rates are time invariant, i.e. the barrier state does not change over time in a given event path. By combining the probability that the leak path exists and the resultant flow rate, it is possible to calculate an expectation value of the probable mass of CO2 released per year by each individual leak path, and these will range from the small, high frequency releases to very large releases which occur with a remote probability.

Element (Depth, m)	Direction	Leak Path	Internal diameter (")	External diameter (")	Area (m^2)	Base of element TVDSS (m)	Base of element MD (m)	Top of element TVDSS (m)	Top of element MD (m)	Failure Status	Prob	Perm	Flow	Comments
Cement Plug 1	V	1 to 5	0	12.250	0.076	1002.4	1002.4	972.4	972.4	Intact	7.00E-01	0.01	1.70E-01	Initial assumption that if 'failed' then pressure will exceed fracture pressure of formation. If 'impaired' then formation retains integrity. Base of element taken as top of Bunter Sand - length reduced to 30m to include allowance that plug not set on solid foundation
(1111m MD)										Impaired	1.00E-01	100	1.70E+03	
										Failed	2.00E-01	100000	1.70E+06	
Halite Creep	V	1 to 5	0	12.25	0.076	972.4	972.4	813.0	813.0	Intact	9.25E-01	0.01	3.83E-02	Based on behaivour in offset wells/borholes where creep has been observed. Timeframe estimated as 35-50 years to achieve complete closure. If closure occurs, then assumed that permeability will be as per intact cement. Top of Muschelkalk ~813m
										Impaired	7.50E-02	1	3.83E+00	
										Failed	1.00E-04	100000	3.83E+05	
Cement Plug 2	V	1,4,5	0	13.375	0.091	564.4	564.4	427.4	427.4	Intact	9.90E-01	0.01	5.65E-02	Part in formation, part set in casing. If plug #1 'failed' considered more likely that formation would fail, rather than plug itself.
(598m MD)										Impaired	1.00E-02	100	5.65E+02	
										Failed	1.00E-04	100000	5.65E+05	
Cement Plug 3	V	1	0	13.375	0.091	166.4	166.4	79.4	79.4	Intact	9.90E-01	0.01	2.84E-02	Most credible failure mechanism would be corrosion of casing forming leak paths, rather than creation of microannuli within concrete, hence impaired is higher permeability than plugs #1 and #2 (which are set to rock)
(200m MD)										Impaired	1.00E-02	100	2.84E+02	
										Failed	1.00E-04	100000	2.84E+05	
Geological Layers at 600m	V	3	12.25	17.5	0.079	564.4	564.4	514.4	514.4	Intact	9.90E-01	0.1	1.22E+00	Not believed to be a very robust layer - permeability to be confirmed; workshop estimated in range .01 to .1md
										Impaired	1.00E-02	1	1.22E+01	
										Failed	1.00E-04	100000	1.22E+06	
Cement Plug 2 at 13 3/8" shoe	V	3	13.375	17.5	0.065	514.4	514.4	427.4	427.4	Intact	9.90E-01	0.01	1.20E-02	Properties assumed as per Plug 2 in wellbore, although shorter length between bottome of plug and shoe
										Impaired	1.00E-02	100	1.20E+02	
										Failed	1.00E-04	100000	1.20E+05	
13 3/8" casing cement	V	3	13.375	17.5	0.065	427.4	427.4	56.4	56.4	Intact	9.89E-01	0.01	1.51E-02	Set between casing and rock. No CBL run on well.
(above CP2)										Impaired	1.00E-02	100	1.51E+02	
										Failed	1.00E-03	100000	1.51E+05	
13 3/8" casing	H	4,5	13.375	13.75	1.000	166.4	166.4	166.3	166.3	Intact	1.00E-02	0	0.00E+00	Casing assumed to be either intact or failed. Flow rate is just a high value. Space between plugs 2 and 3 assumed to be seawater. A/L terms swapped as below
										Impaired	9.90E-01	100000	3.01E+07	
										Failed	0.00E+00		0.00E+00	
13 3/8" casing cement (H)	H	4	13.375	17.5	1.000	166.4	166.4	166.3	166.3	Intact	1.00E-02	0.01	2.54E+02	Set between casing and rock. No CBL run on well. Length set to 4" (0.1m). Circumference =42" (1m), assume 1m exposed height, therefore Area set to 1m2 manually
(~200m MD)										Impaired	5.00E-01	100	2.54E+06	
										Failed	4.90E-01	100000	3.01E+07	
13 3/8" casing cement (V)	V	5	13.375	17.5	0.065	166.4	166.4	56.4	56.4	Intact	9.89E-01	0.01	1.63E-02	Set between casing and rock. No CBL run on well.
(~200m MD)										Impaired	1.00E-02	100	1.63E+02	
										Failed	1.00E-03	100000	1.63E+05	
Dummy Plug 2	V	2	0	13.375	0.091	564.4	564.4	427.4	427.4	Intact	9.90E-01	1.00E+06	5.65E+06	Dummy entry to allow for Path 2 to account for Hydraulic lock and consequential failure. Permeability is high value to avoid being counted in calculations
										Impaired	1.00E-02	1.00E+06	5.65E+06	
										Failed	1.00E-04	1.00E+06	5.65E+06	

Table 14 43/21-1 Barrier Performance Data

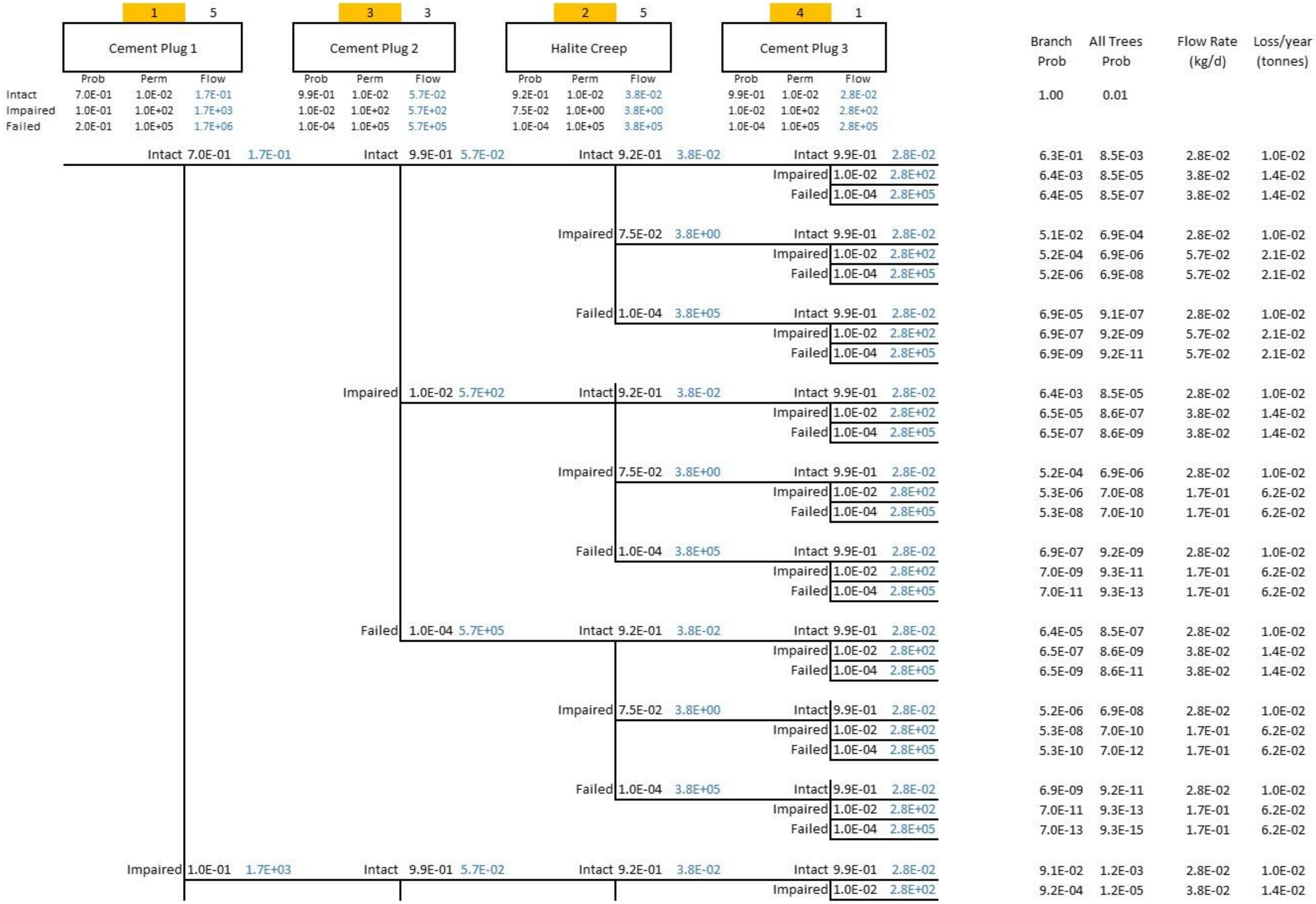


Figure 37 43/21-1 Partial Event Tree (Leak Path 1 Only)

12.3 CO2 Releases

Risked CO2 release rates have been calculated using the methodology described above for 43/21-1 for the other two on-structure legacy wells (42/25-1, 42/25d3) and an example of a future decommissioned CO2 injection well, together with two nearby off-structure wells (43/21-2 and 43/21-3) which should not see CO2, but which it is instructive to include in this report.

A summary of the cumulative probability of increasing leak scenarios for CO2 is shown in Figure 39, which indicates that for on-structure wells, the probability of a leak of more than 1000 tonnes of CO2 per year is less that 1E-5.

For off-structure wells, a very conservative approach was taken in estimating failure of the monitoring program to observe CO2 being injected past the spill point. Due to the abandonment design of these wells, this would lead to a larger maximum leak rate risk than for on-structure wells, but the risk is remote, and would certainly be detected by the provisions of the Measurement, Monitoring and Verification plan (MMV) which renders the mitigated risk negligible. If this were to occur, injection into the store would cease and remedial action taken to the subsurface injection plan to prevent further migration out of the structural closing contour.

Note that for all cases, reservoir deliverability (PI) has been assumed as infinite – this is another conservative assumption which would limit worst case leak rates, and will be incorporated in subsequent updates.

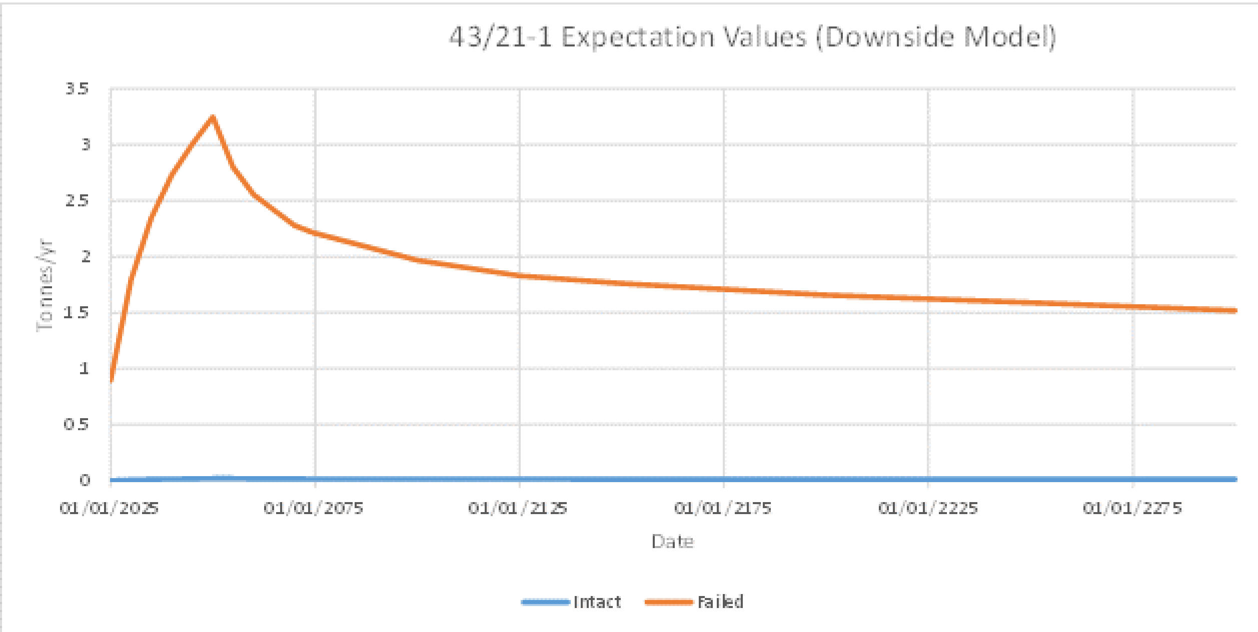


Figure 38 43/21-1 CO2 Leak Rate Expectation vs. Time

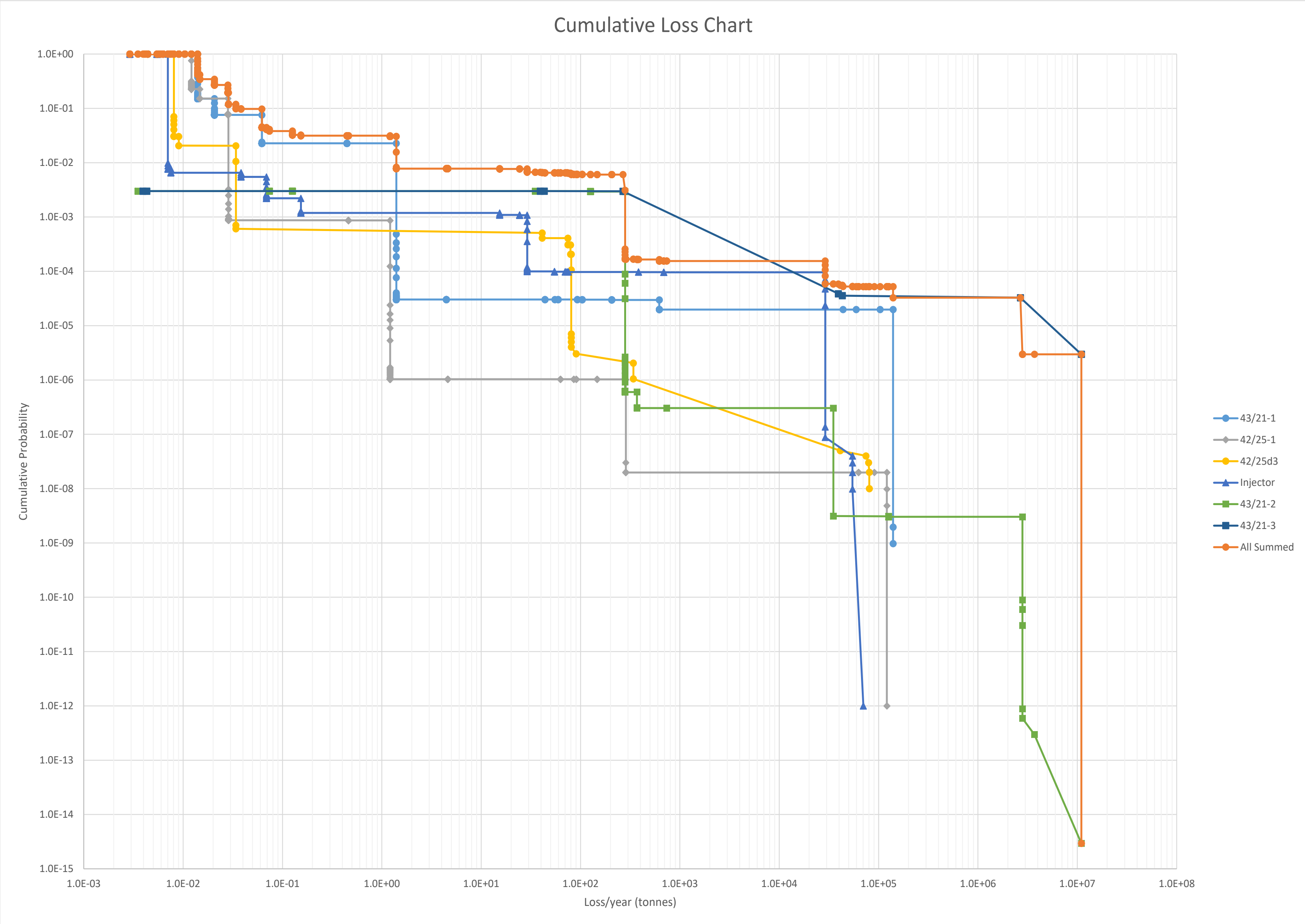


Figure 39 All Wells – Cumulative Probability of CO2 Leakage

12.4 Off-Structure Legacy Well Brine Releases

The methodology applied to CO2 release estimation in the previous section was also applied to off-structure legacy wells, which will see an increase in the regional aquifer in which they are placed. The Garrow field (Alpha Petroleum) is still on production, and so as an example for well 42/25a-G1, two cases have been modelled; the first with a 30m environmental plug at the surface, the second with a 100m plug isolating the Bunter as a lateral barrier.

Figure 40 shows the cumulative probability of brine leaks from off-structure wells at time 25 years (maximum aquifer over-pressure), indicating that the likelihood of a leak of >~2000bbl/d (1E5 tonnes/year) is around 6E-4 for the three wells closest to structure. For all other wells the probability of a similar leak rate approaches 1E-5.

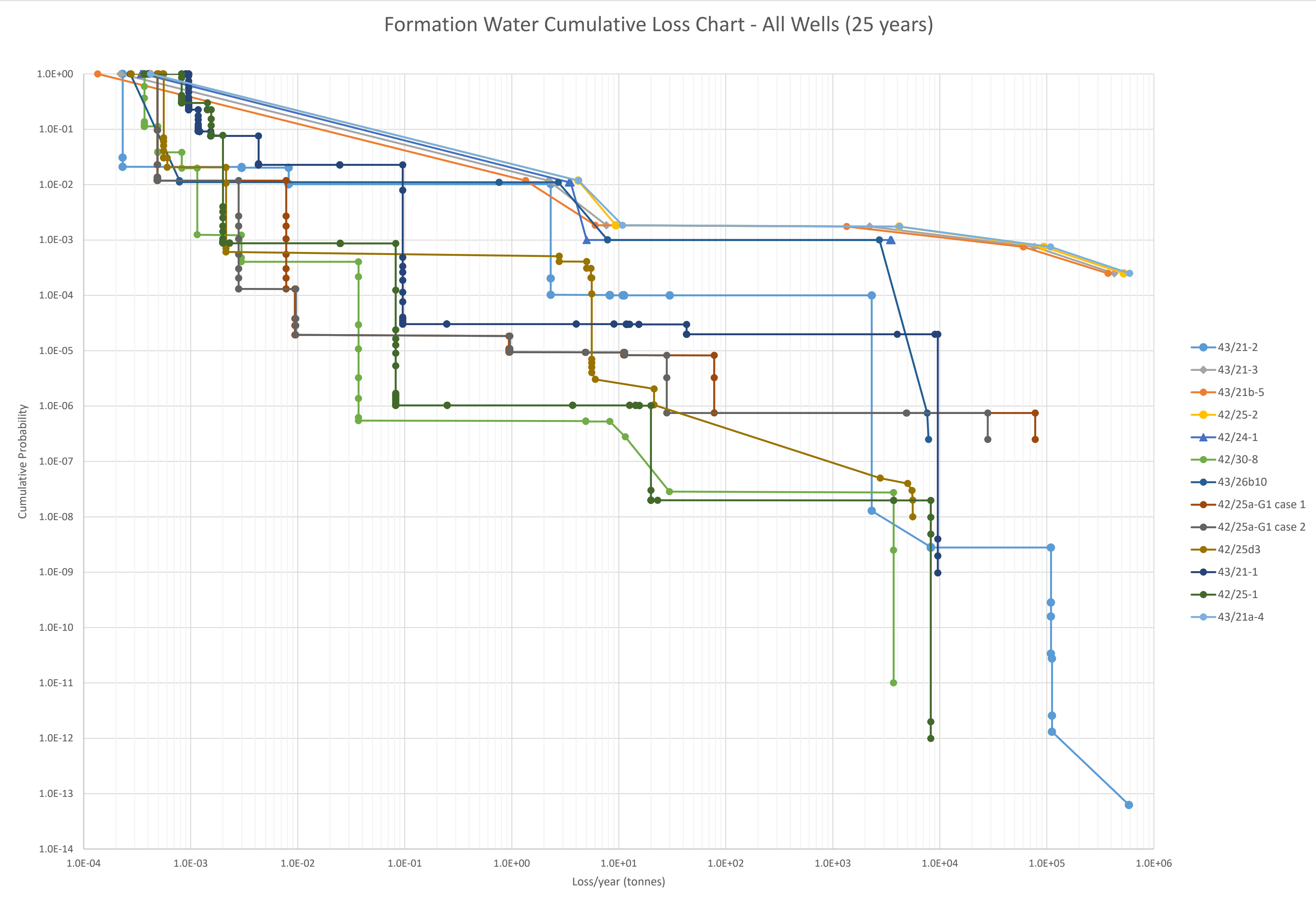


Figure 40 All Off-Structure Wells – Cumulative Probability of Brine Leakage (25 years)

13 Heriot Watt University Fine-Grid Simulator Leakage Assessment

Although the probability of barrier states used in the preceding leakage assessments are considered to be as accurate as the available data allows, the leak rate flow calculations themselves are inherently conservative, primarily because the Bunter sandstone reservoir is assumed to have infinite deliverability (production index, PI), and so the driving pressure remains constant as leak rate increases. In reality, as the rate increases, a pressure drop is induced in the porous sandstone which reduces driving pressure at the leak and hence rate through it.

Similarly, for large defects and impairment, a Darcy equivalent permeability model has been used, but which does not model friction pressure losses in micro-annuli for example.

In addition, the grid-based approach allows some more realistic modelling of the leak path generation via casing corrosion for brine leakage from off-structure wells.

For these reasons, Heriot Watt University were commissioned to use their probabilistic fine-grid well model[8] to give a "Best Available Technology" (BAT) approach to addressing the conservatism in the existing QRA.

The results of this work are predicted to result in a reduction in risked leak rates, but are not available at the time of writing, and are likely to be finalised at the end of Q2 2022. The modelling work will be available for use after this date.

[8] SPE-200608-MS, Application of Numerical Flow Simulation Methods to Risk-Based Well Decommissioning Design, Caroline Johnson, Morteza Haghighat Sefat, and David Davies, Heriot-Watt University, 2020

14 Discussion

14.1 Cement Resistance to Future CO_2 Storage

This is a large subject with extensive research carried out over the years which is still on-going. This section presents a brief summary of the suitability of cements already placed in the legacy wells on and around Endurance. It is not intended to be an exhaustive discussion.

Most of the cement that was installed during well construction and abandonment of these wells identified used Class G cement with the exception of 42/25d-3 where CorrosaCem NP (Thermalock) CO_2 "resistant" cement was used in the lead slurry for the 7" liner, and 43/21-1 which used Class B cement throughout.

There is a large volume of literature data that supports the fact that the use of non-Portland based specialized CO_2 resistant cement is not necessary for effective zonal isolation, which instead can be achieved using standard oilfield Portland cement blends. It has been documented that cement degradation is expected to take tens of thousands of years for CO_2 to chemically modify a 100m sheath of well bonded Portland based cement, based on reaction rate. If reaction with CO_2 does take place resulting in carbonate precipitation, this can actually lead to seals being improved as the porosity is "plugged" by carbonation.

The key variable is often geometry – annular cement is rarely classed as lateral barrier, whereas a plug with CO2 impinging from below is likely to be, regardless of cement type. However, basic practices of good centralization of casing, efficient borehole mud removal and effective cement placement avoiding micro-annuli remain the cornerstone of effective isolation during well construction and abandonment.

14.2 Overall Well Integrity Risk

14.2.1 CO2 Leakage on Structure

There are three wells on the Endurance structure; 43/21-1 drilled by Mobil in 1970, 42/25-1 drilled by bp in 1990, and 43/25d-3 drilled as a CO2 appraisal well by National Grid in 2013. All will be in contact with CO2.

- 43/25d-3 was abandoned largely in-line with modern guidance, has two barriers in the form of a combination abandonment plug and has a full record of all operations carried out on the well. The Rot halite will have swollen against the annular cement around and above the 9 5/8" casing shoe providing additional integrity. This well presents a very low risk of a major leak.
- 42/25-1 has limited documentation on wellbore barrier verification, and although both primary and secondary annulus and wellbore containment is present, only the lower primary plug is set in formation that has sufficient fracture gradient at maximum anticipated final reservoir pressure. This barrier was set on bottom of open hole, so is expected to be present and intact, though un-verified. The Rot halite above the Bunter is also expected to form an additional seal, but will not have fully crept to form a cement-equivalent barrier until the mid-2040s, although potential flow rates through the salt today would be very small. This well presents a low risk of leakage.
- 43/21-1 targeted the Bunter sandstone on-structure, and has a primary barrier isolating the Bunter sandstone in open hole, and a secondary barrier across the open hole and 13 3/8" casing at the shoe. The fracture gradient at the secondary barrier would not withstand final CO2 injection storage pressure, so the well has only one cement barrier to CO2 leakage from the store. There is no evidence that this plug was set on a base, although it is thought this is

unlikely as there is similarly no evidence for the secondary plug 2 being set on a base, yet it was tagged (it would have slumped completely with no base) some 81ft lower than calculated which tallies with the placement simulation. Applying this same logic to the primary plug, it is likely that the plug is present and has isolated the Bunter. Furthermore, halite creep is expected to have occurred to form a second barrier above the Bunter, thereby giving confidence that the Bunter is isolated in this well and presents a low risk of leakage.

14.2.2 CO2 Leakage off Structure

Unless CO2 migrates under the spill point of the structure, off-structure wells will not be exposed to CO2 – containment within the store is the primary purpose of a CCUS project, and detection of CO2 outside of the structure would certainly lead to a cessation of injection until the issue was understood and resolved.

That said, two nearby off-structure wells were evaluated in particular to determine their potential for CO2 containment.

It should also be noted that the majority of off-structure wells, both close to Endurance and in the wider regional aquifer, pass through the Bunter on their way to deeper gas-bearing targets (often the carboniferous). This means that Bunter isolation is usually by annular cement around production or intermediate casing. As the brine in the Bunter will not flow to the seabed naturally, there has not been any requirement to isolate the Bunter with a lateral barrier in the majority of regional well abandonments.

- 43/21-2 accessed the Leman sandstone reservoir below the Bunter, and as such, the Bunter is isolated by 13 3/8" intermediate casing and annular cement, followed by 9 5/8" annular cement laterally. As there is only annular cement present, lateral impingement of wet CO2 (carbonic acid) would create a layer of degraded cement which may expose the casing to corrosion and perforation through any defects or voids in the cement (annular cement alone not counted as a barrier), although there is a laterally extensive plug across all of the cut casing strings below the mudline which may provide further delay. Based on this, it must be concluded that in the case that CO2 migrates out of the store under the spill point, this well may be a potential leak path. From the CBL, there appears to be a micro-annulus between the 9 5/8" casing and its cement, but this is unlikely to be material to the leakage argument as the corrosion effects of CO2 will dominate anyway. This risk is remote, and would certainly be detected by the provisions of the Measurement, Monitoring and Verification plan (MMV) which renders the mitigated risk negligible.
- 43/21-3 is a similar design to 43/21-2 in that it accessed the Leman sandstone reservoir below the Bunter, but in this well, the 9 5/8" TOC is below the Bunter, and so isolation is only by 13 3/8" intermediate casing and annular cement, above which is effectively open to the seabed. Based on this, it must be concluded that in the case that CO2 migrates out of the store under the spill point, this well may be a potential leak path. This risk is remote, and would certainly be detected by the provisions of the Measurement, Monitoring and Verification plan (MMV) which renders the mitigated risk negligible.

14.2.3 Brine Leakage Off-Structure

The risk of CO2 leakage via a leak path associated with a legacy well is primarily a risk for the on-structure wells as the off-structure wells should not see any CO2 assuming the plume does not migrate beyond the spill point. The off-structure wells will however experience an increase in pressure within the Bunter sandstone due to displacement of brine by CO2 from Endurance into the regional aquifer.

Isolation of the annulus corresponding to the hole section where the Bunter sandstone was drilled varies from long cemented intervals to uncemented annuli (but with adequate fracture gradient to the shoe above), with a number of wells having limited data available. Laterally extensive barriers are generally not present nor would be expected in these well designs and abandonments from the period, although there are no wells with direct brine leak paths to the seabed.

The key to evaluating the potential for over-pressured brine to leak from off-structure wells is the likelihood of brine coming into contact with casing. As the brine is anoxic, corrosion rates are very low, and difficult to evaluate, and so a conservative corrosion rate of ~0.1mm per year has been assumed as the worst case, should brine be in contact with casing and corrosion products are able to be dispersed allowing fresh contact. The potential for annular cement degradation, thereby allowing brine-casing contact, has been evaluated in the semi-quantitative risk assessment, with results presented in Section 12.4, but in summary,the cumulative probability of a brine leak of >2000 bbl/d from the closest two off structure wells under worst case assumptions and over-pressure is around 6E-4.

Wells further away have an even lower risk of leakage, approaching 1E-5 for a similar leak rate.

14.2.4 Remediation

It is feasible to re-enter legacy wells even though they have been abandoned. These jobs have been done in the industry before, but are non-routine, and success is not guaranteed.

Risks of entering these wells with the aim of abandoning them to modern standards may also make matters worse – not only is there a risk of not being able to enter the original reservoir section, but if the cement plugs are indeed present, drilling through them will risk risking off in a new direction and having to abandoned a second penetration.

Furthermore, halite creep that has occurred and created additional isolation will be disturbed, removing that isolation until creep begins again and a new seal is established.

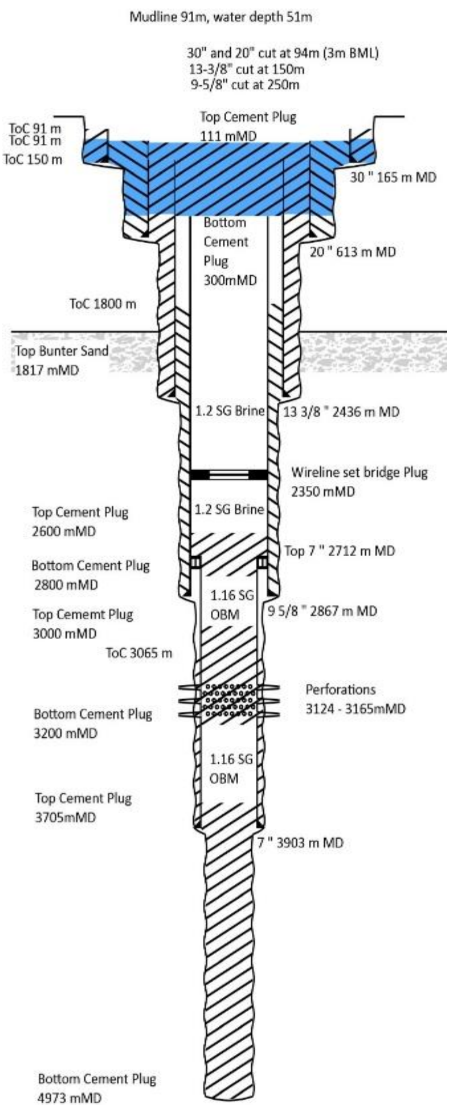
Therefore, pre-emptive re-entry and remediation is not recommended.

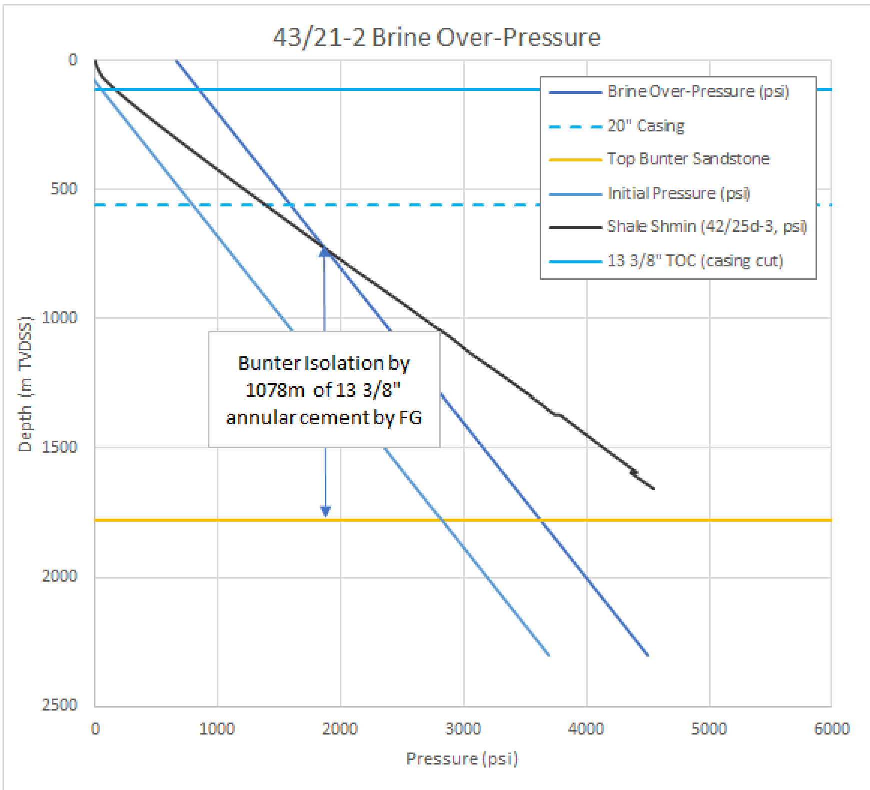
15 Appendices

15.1 Off-Structure Well Details

15.1.1 43/21-2

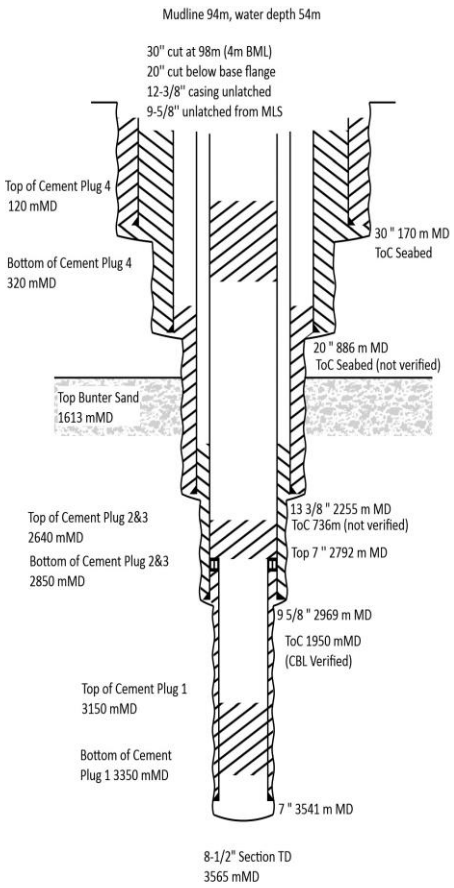
- Well status AB3 – permanently abandoned or casing cut below mudline
- Brine over-pressure 800psi
- Shmin cross-over within annular cement interval
- Bunter isolated behind 1078m 13 3/8″ annular cement by fracture gradient
- 3/8″ cement column extends to casing cut below mudline should Shmin not be exceeded
- Lateral plug present below mudline

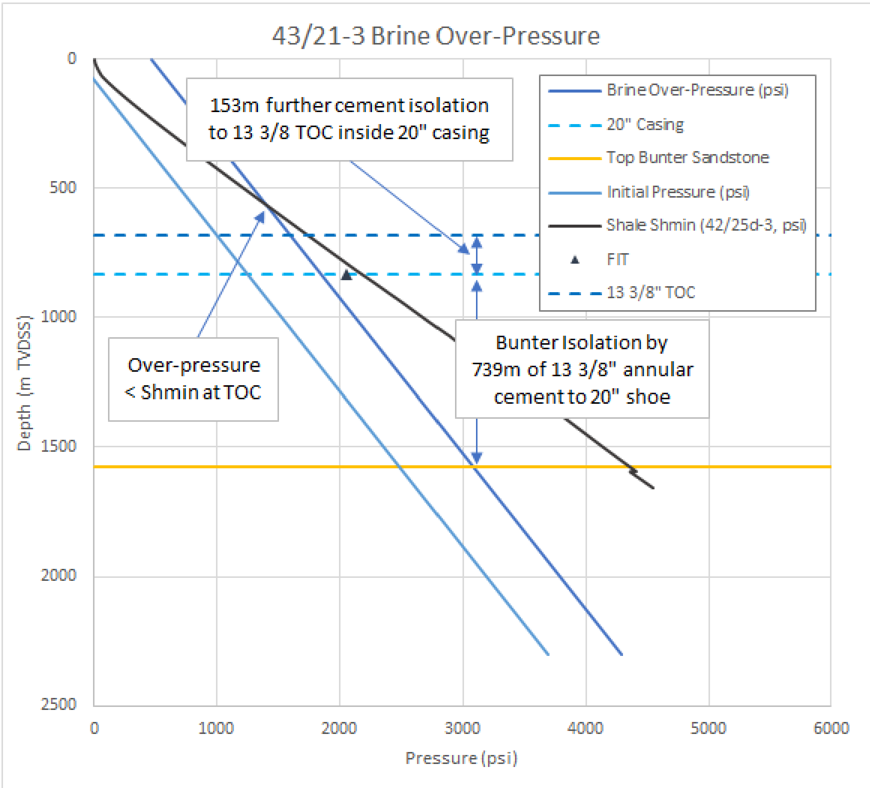




15.1.2 43/21-3

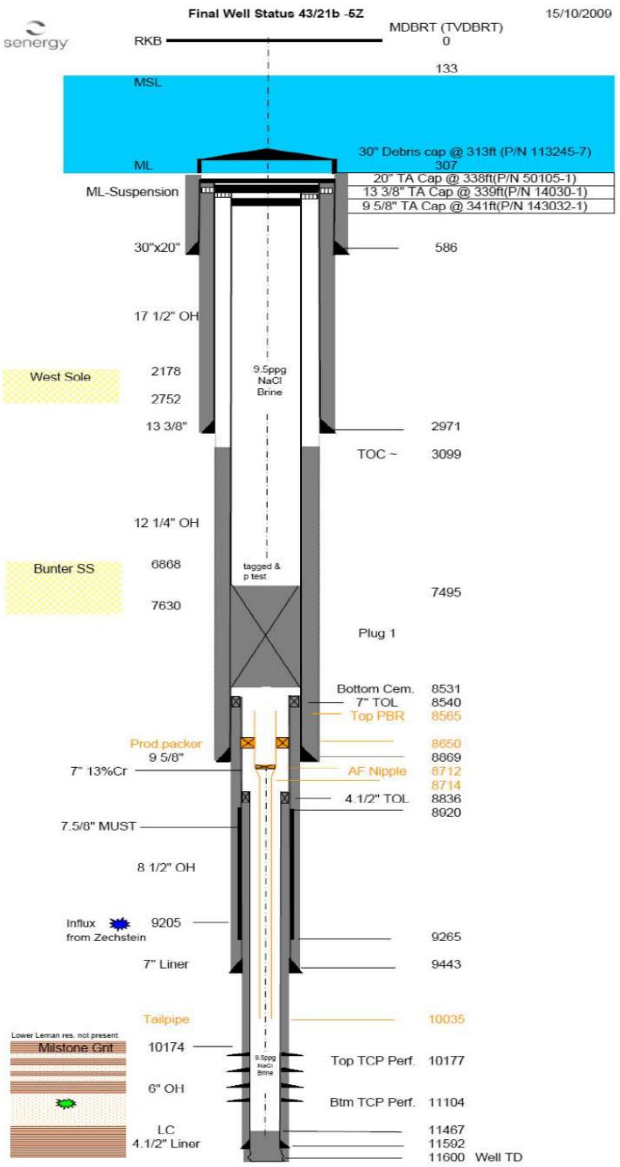
- Well status AB3 – permanently abandoned or casing cut below mudline
- Brine over-pressure 600psi
- Bunter isolated behind 739m 13 3/8” annular cement to 20” shoe
- Further 149m cement should Shmin not be exceeded inside 20” shoe
- Shmin cross-over above annular cement interval

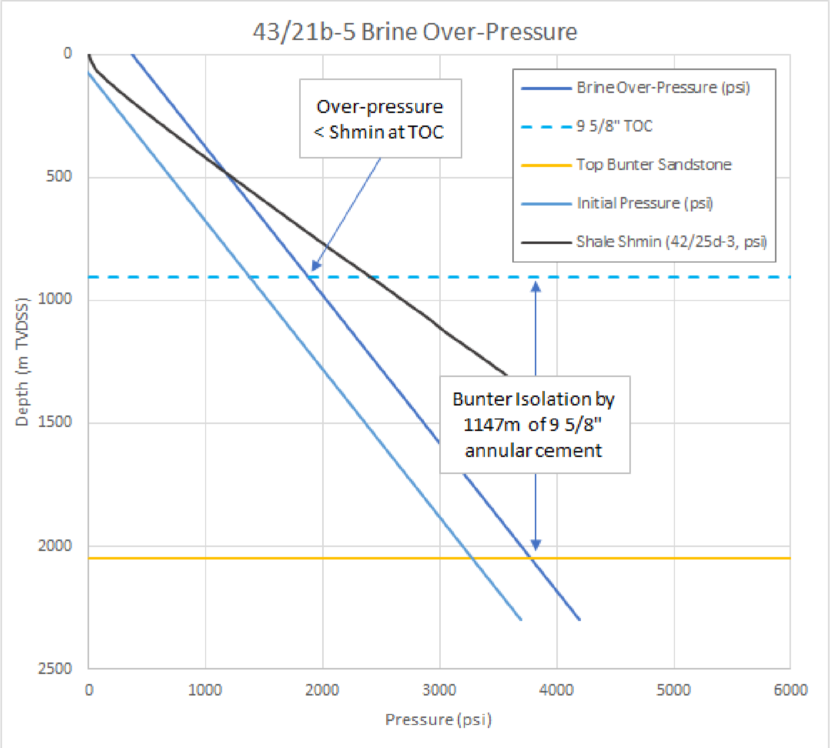




15.1.3 43/21b-5

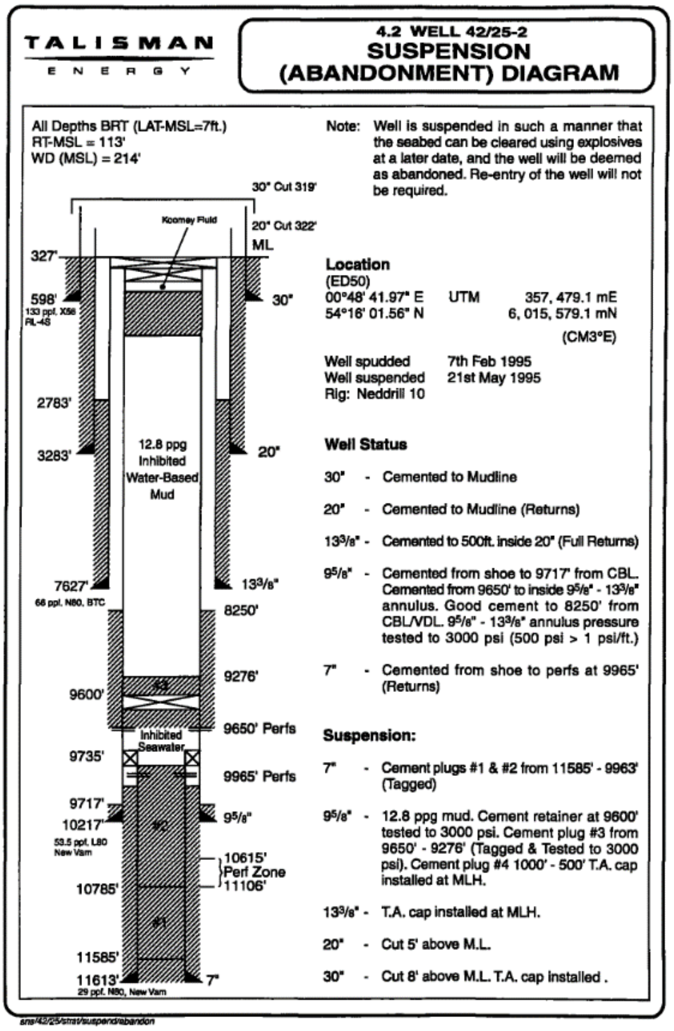
- Well status AB3 – permanently abandoned or casing cut below mudline
- Brine over-pressure 500psi
- Bunter isolated behind 1147m 9 5/8" annular cement. Open to mudline above TOC
- Shmin cross-over above annular cement interval

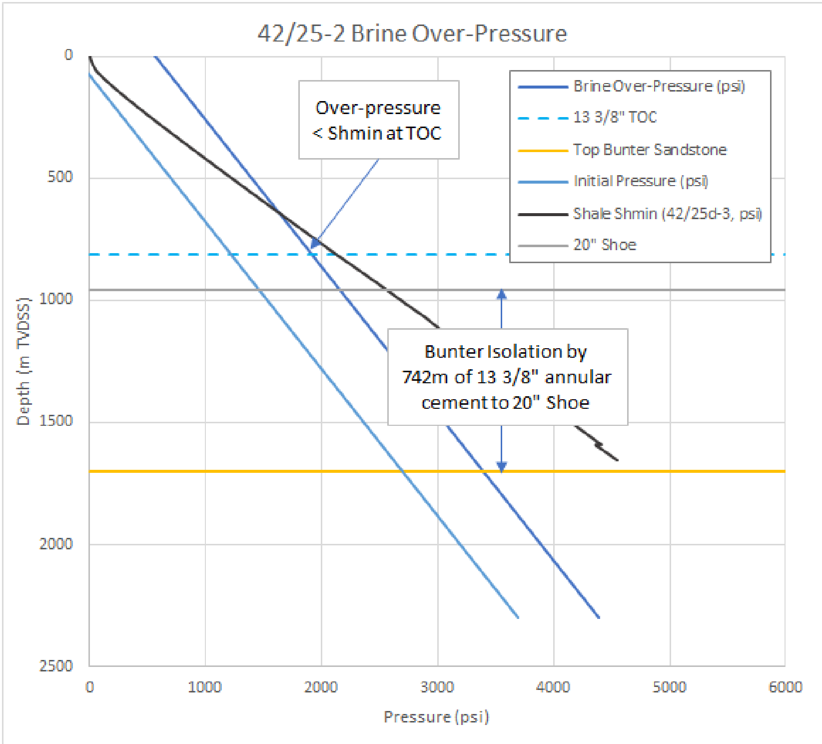




15.1.4 43/25-2

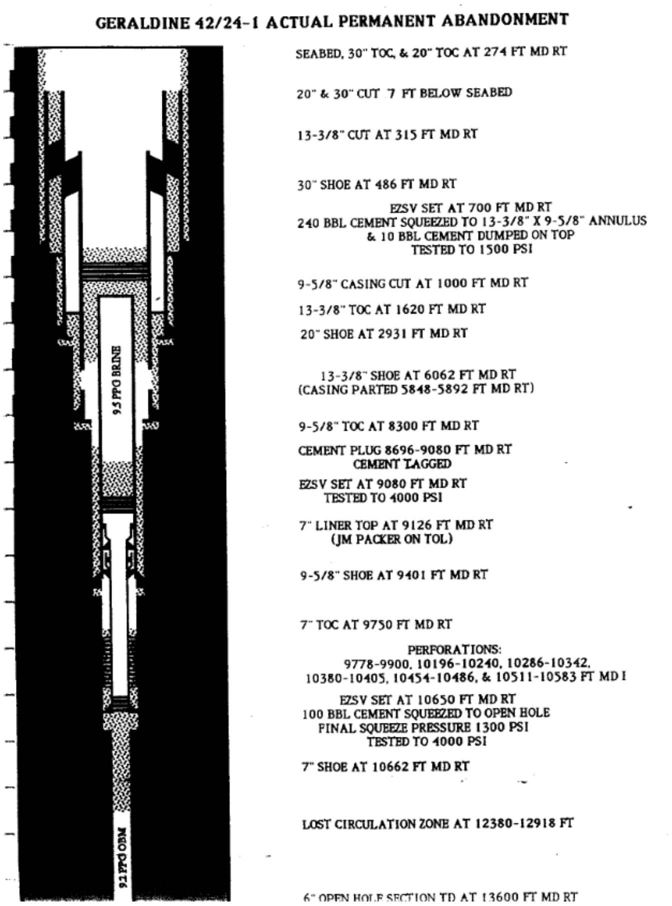
- Well status AB3 – permanently abandoned or casing cut below mudline
- Brine over-pressure 700psi
- Bunter isolated behind 742m 13 3/8” annular cement to 20” shoe
- Shmin cross-over above annular cement interval

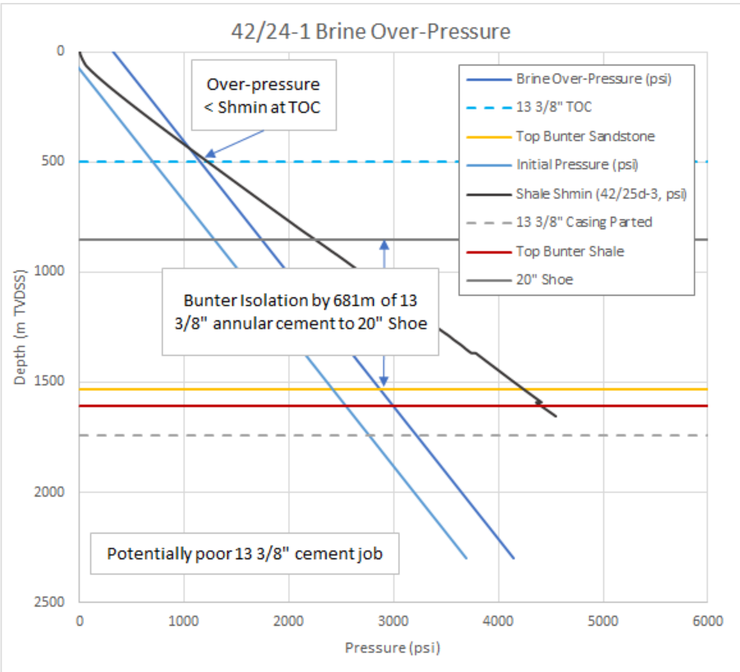




15.1.5 42/24-1

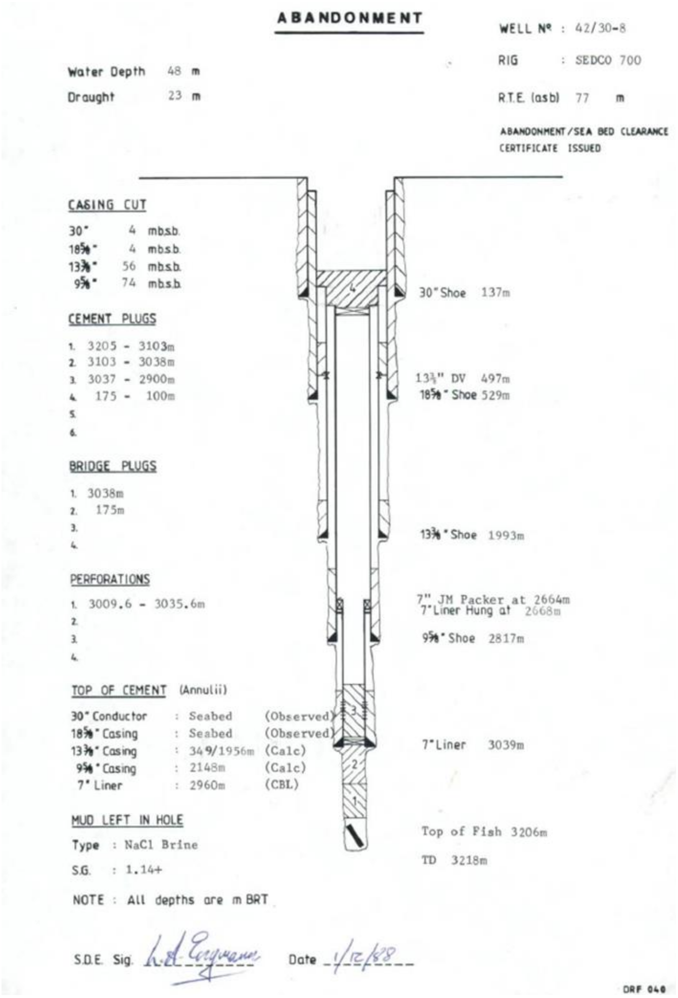
- Brine over-pressure 450psi
- Bunter isolated behind 681m 13 3/8" annular cement to 20" shoe
- Shmin cross-over above annular cement interval at 20" shoe
- Further 353m cement inside 20" shoe is Shmin not exceeded
- Well status AB3 – permanently abandoned or casing cut below mudline
- Potentially poor 13 3/8" cement job – casing parted while running below top of Bunter sand. TOC assumed as per well documentation's "top of good cement"

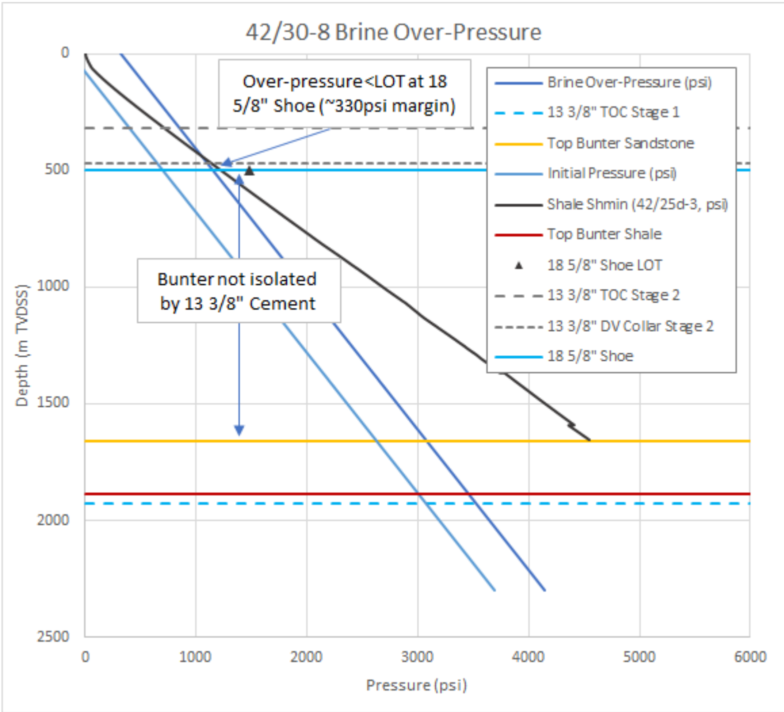




15.1.6 42/30-8

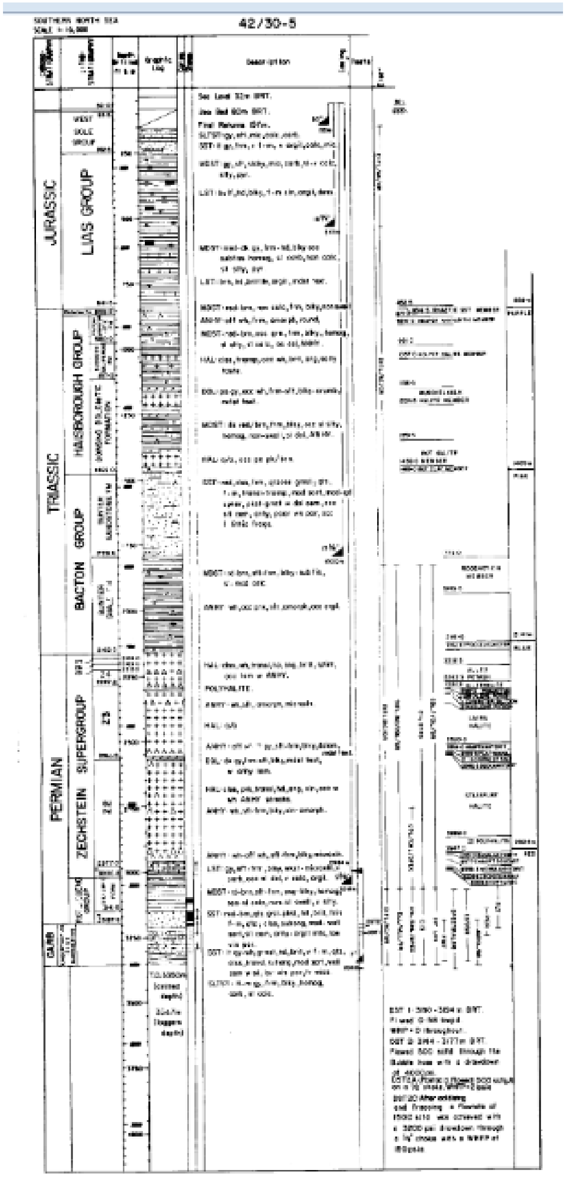
- Well status AB3 – permanently abandoned or casing cut below mudline Brine over-pressure 450psi
- No cement isolation of Bunter
- Isolation only by FIT and Shmin at 18 5/8" shoe

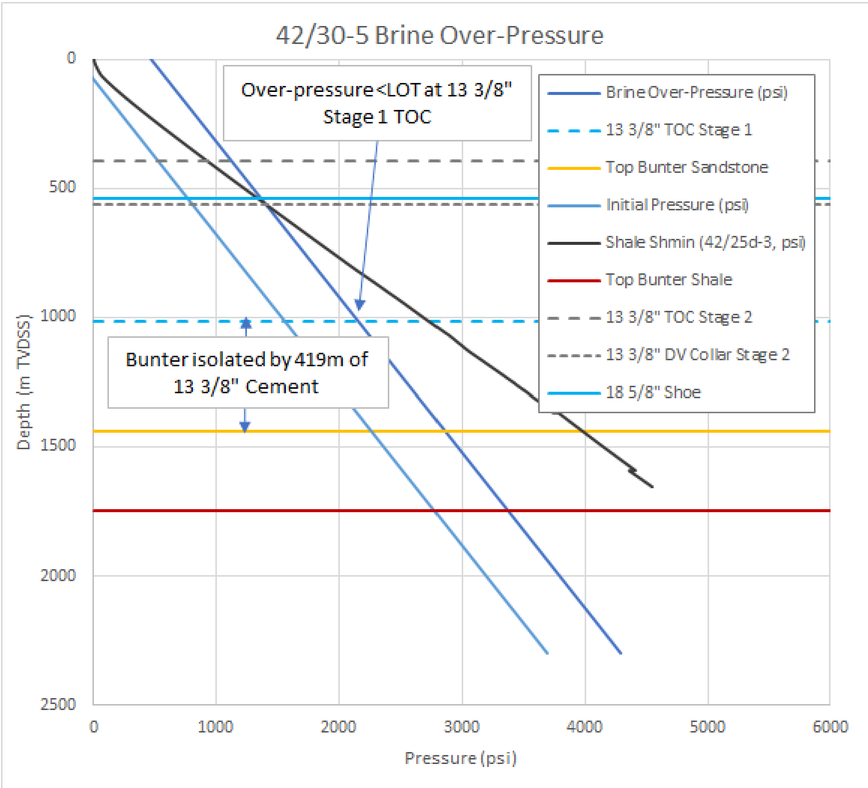




15.1.7 42/30-5

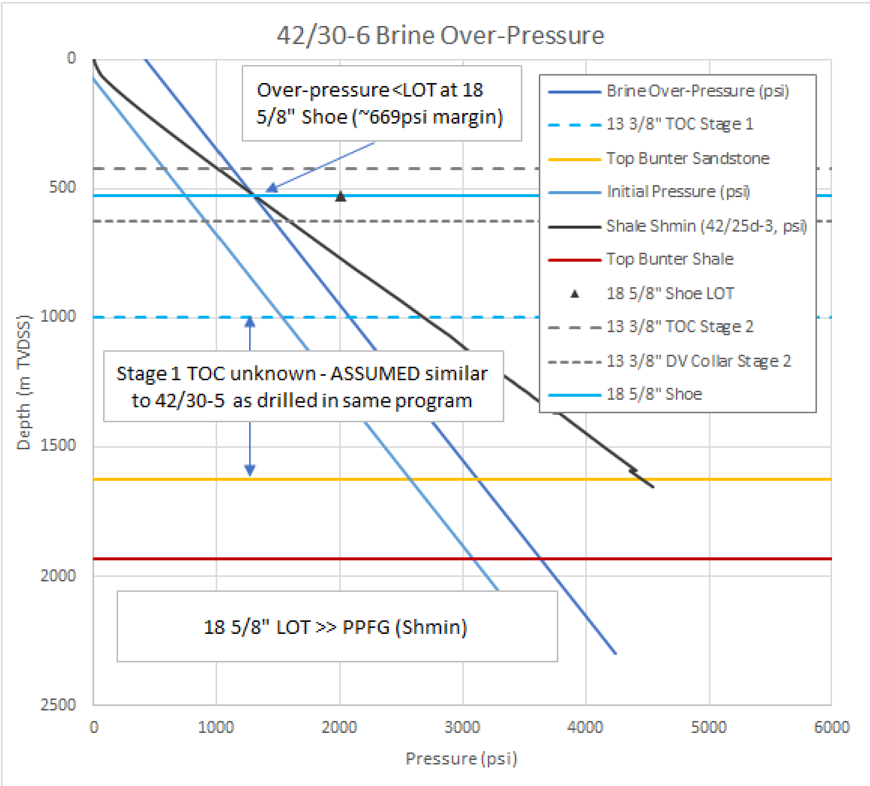
- Well status AB3 – permanently abandoned or casing cut below mudline
- Brine over-pressure 600psi
- No abandonment schematic available – poor photocopy of geological cross-section only
- Bunter isolated behind 419m 13 3/8" annular cement to 1st stage job TOC
- Shmin cross-over above annular cement interval





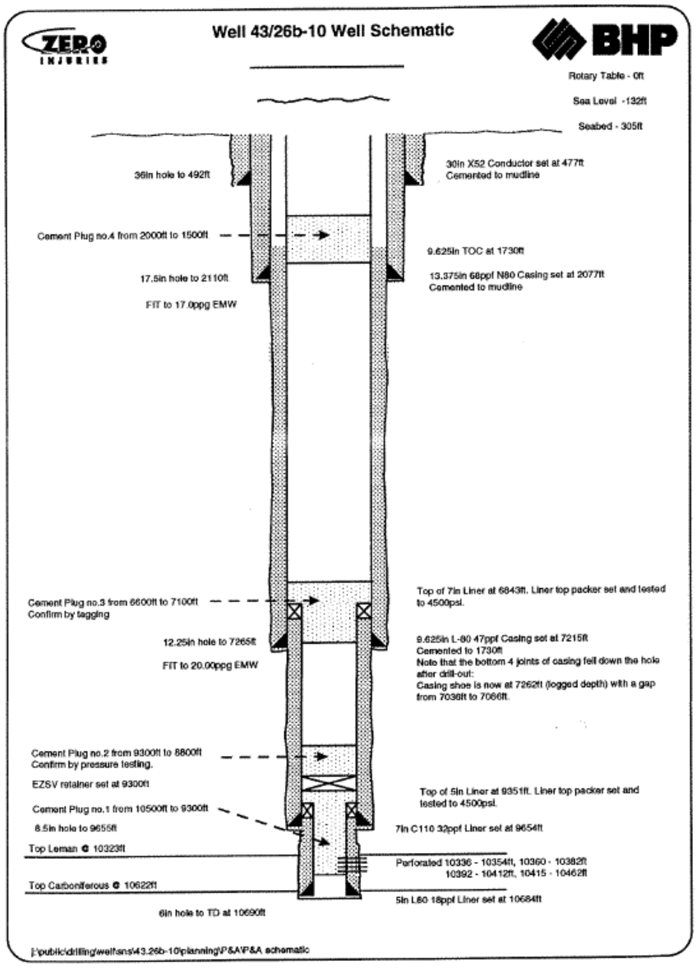
15.1.8 42/30-6

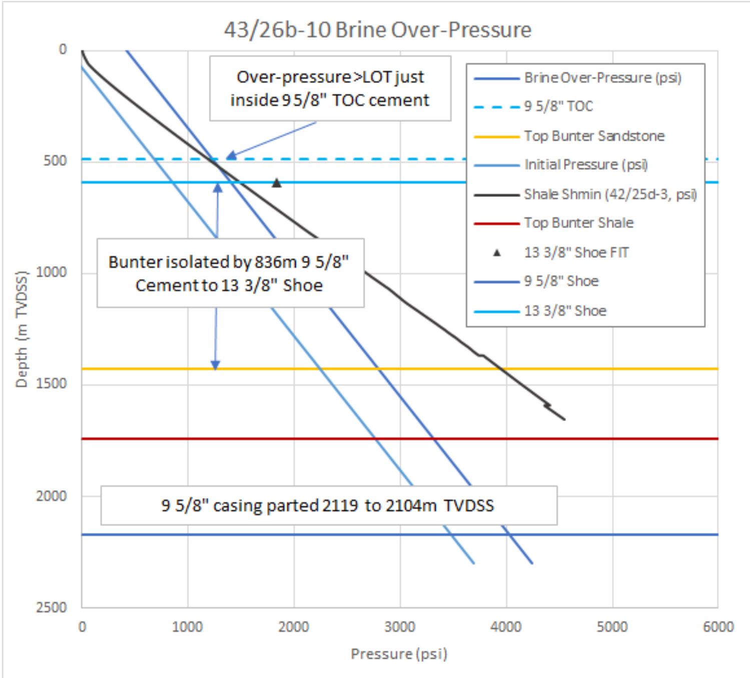
- Well status AB3 – permanently abandoned or casing cut below mudline
- Brine over-pressure 550psi
- No abandonment schematic available
- Bunter annular cement isolation unknown – though may be similar to 42/30-5 as drilled in same program (i.e. ~400m 13 3/8" annular cement)
- Shmin cross-over above potential annular cement interval
- 18 5/8" LOT >> Shmin



15.1.9 43/26b-10

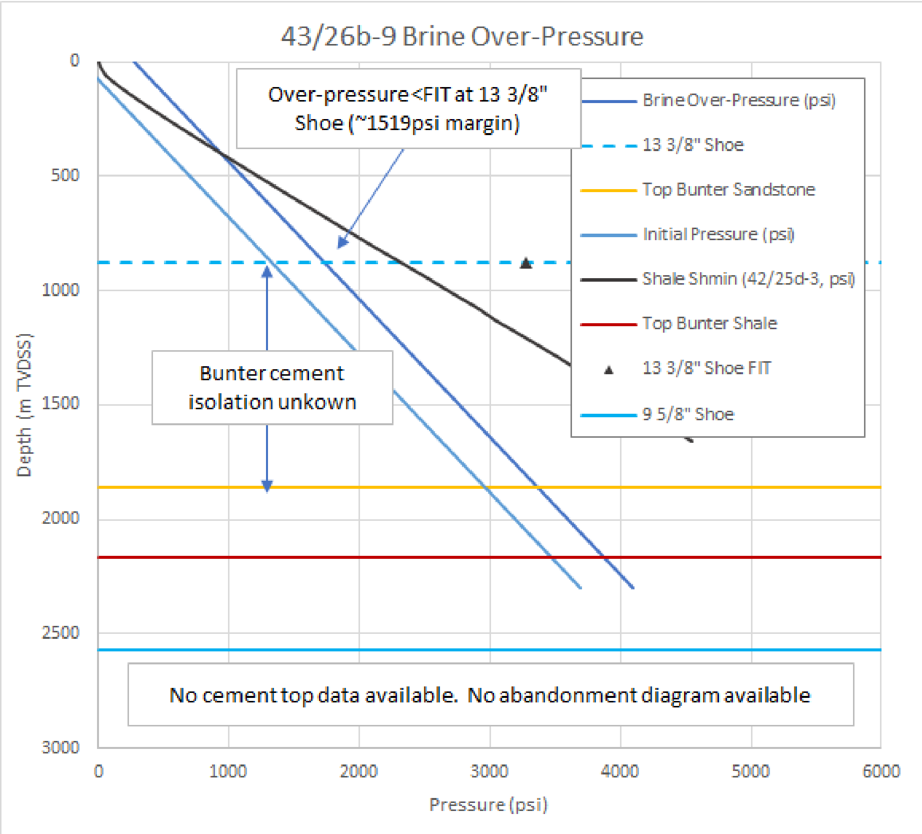
- Brine over-pressure 550psi
- Bunter isolated behind 836m 9 5/8" annular cement 20 13 3/8" shoe
- Shmin cross-over just within annular cement interval
- Well status AB3 – permanently abandoned or casing cut below mudline





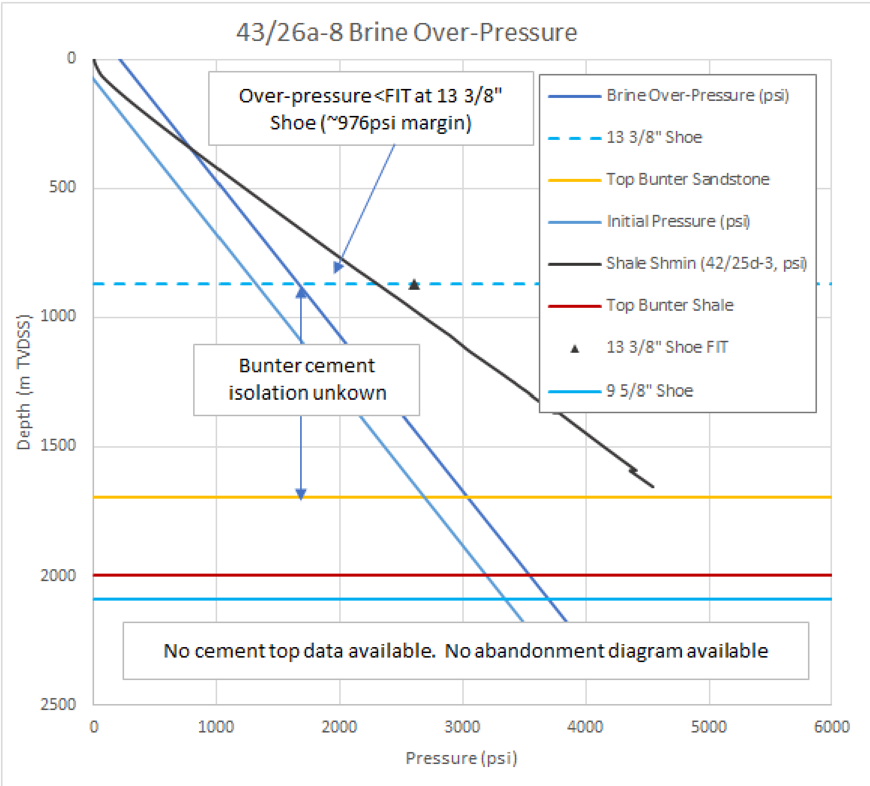
15.1.10 43/26b-9

- Well status AB3 – permanently abandoned or casing cut below mudline
- Brine over-pressure 400psi
- No abandonment schematic or cement information available
- Bunter annular cement isolation unknown
- Isolation by FIT and Shmin at 13 3/8" shoe (~1519psi margin)



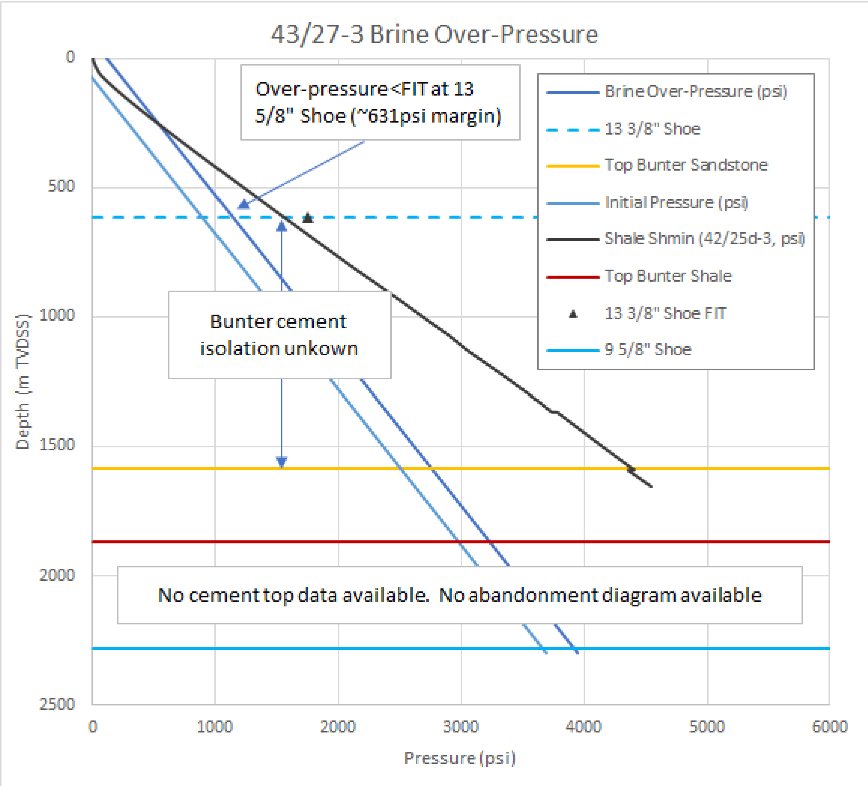
15.1.11 43/26a-8

- Well status AB3 – permanently abandoned or casing cut below mudline
- Brine over-pressure 350psi
- No abandonment schematic or cement information available
- Bunter annular cement isolation unknown
- Isolation by FIT and Shmin at 13 3/8" shoe (~976psi margin)



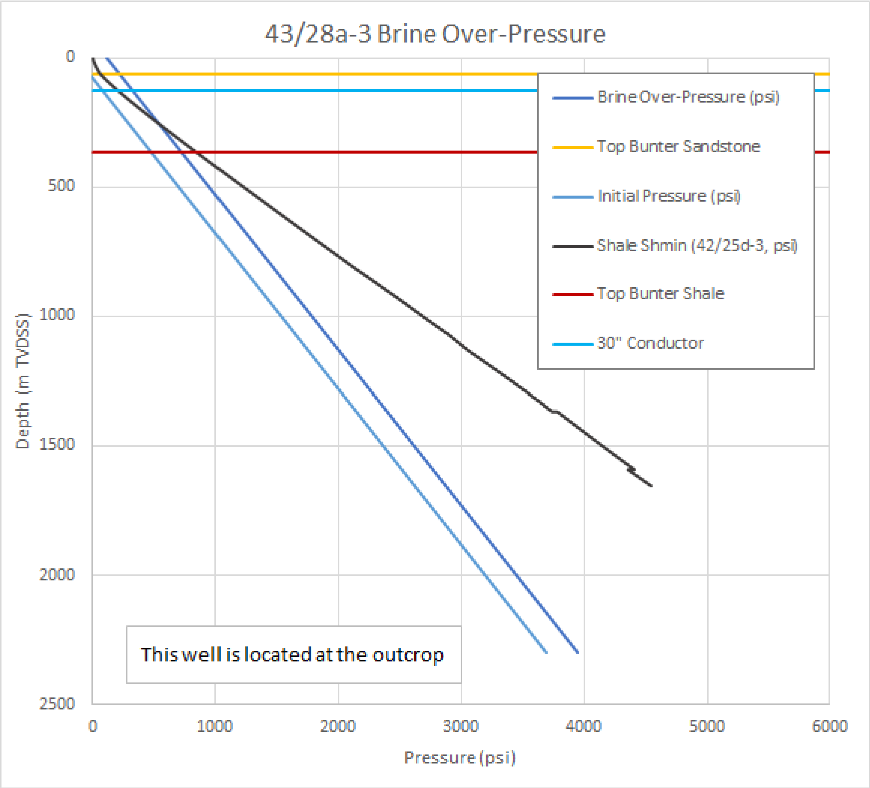
15.1.12 43/27-3

- Well status AB3 – permanently abandoned or casing cut below mudline
- Brine over-pressure 250psi
- No abandonment schematic or cement information available
- Bunter annular cement isolation unknown
- Isolation by FIT and Shmin at 13 3/8" shoe (~631psi margin)



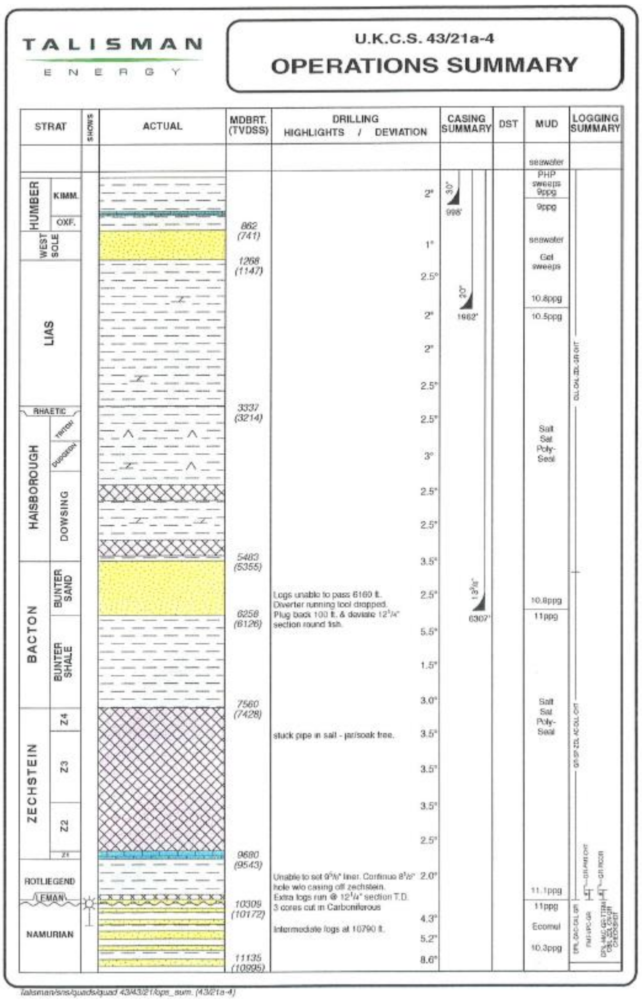
15.1.13 43/28a-3

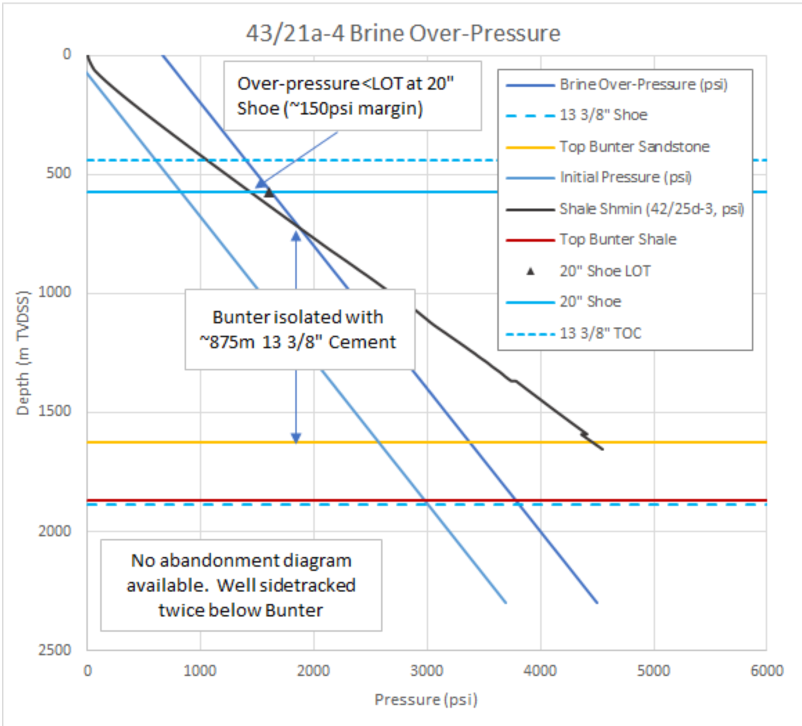
- Well status AB3 – permanently abandoned or casing cut below mudline
- Brine over-pressure 250psi
- No abandonment schematic or cement information available
- This well is at the outcrop – Bunter is not isolated



15.1.14 43/21a-4

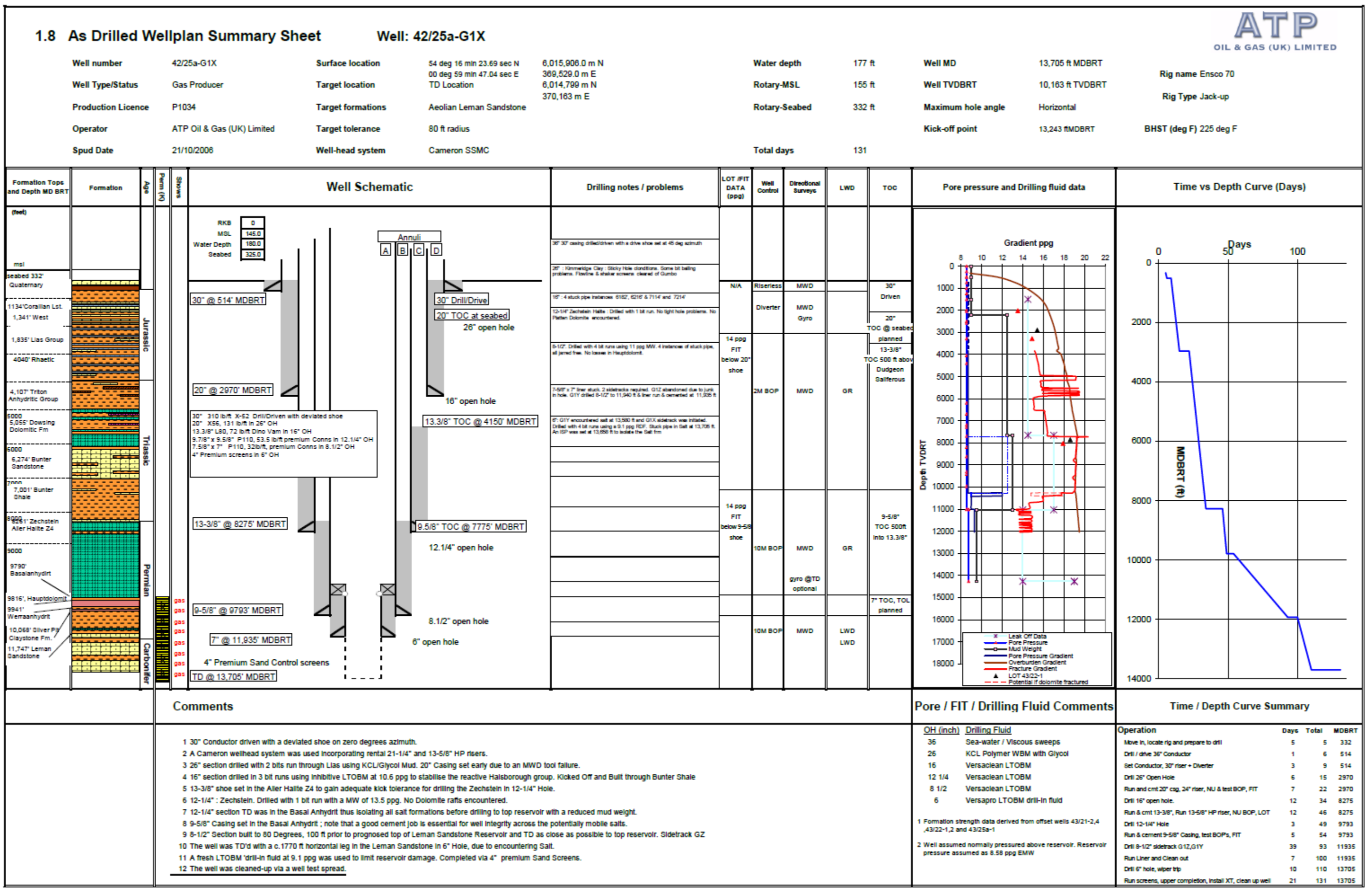
- Well status AB3 – permanently abandoned or casing cut below mudline
- Brine over-pressure 800psi
- No abandonment schematic available
- Isolation by ~875m 13 3/8" annular cement to Shmin, also OP<LOT at 20" shoe (~150psi margin)

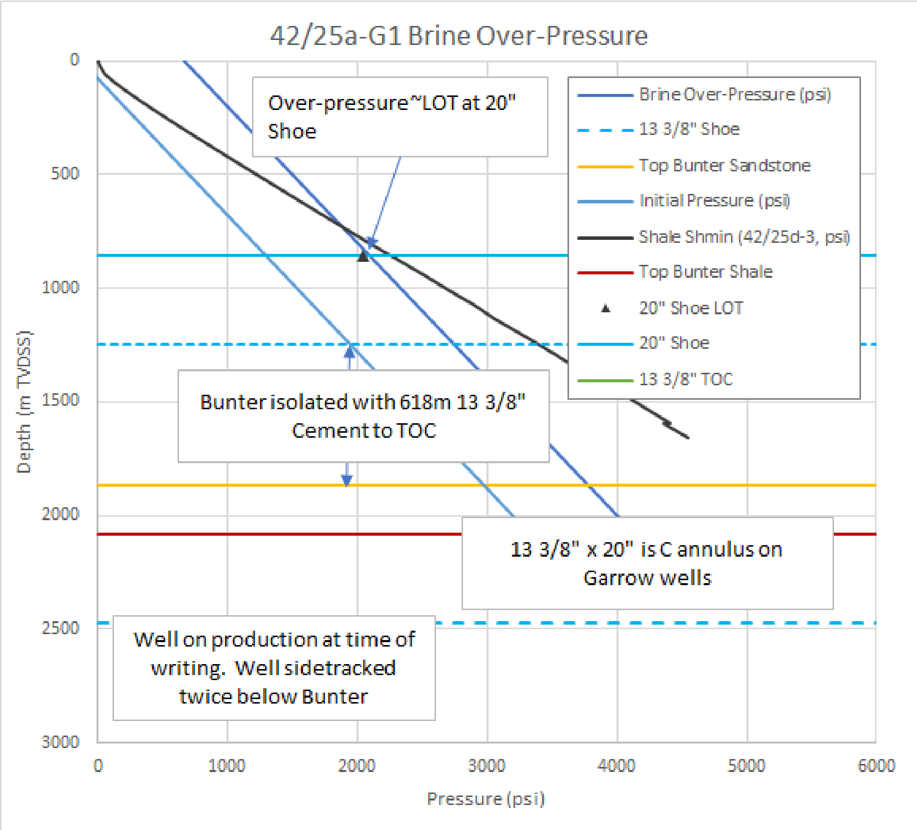




15.1.15 Garrow 42/25a-G1

- Well status – development well on production
- Brine over-pressure 800psi
- Isolation by 618m 13 3/8" annular cement to TOC.
- 13 3/8" x 20" annulus open above TOC (assumed for when abandoned and wellhead removed)

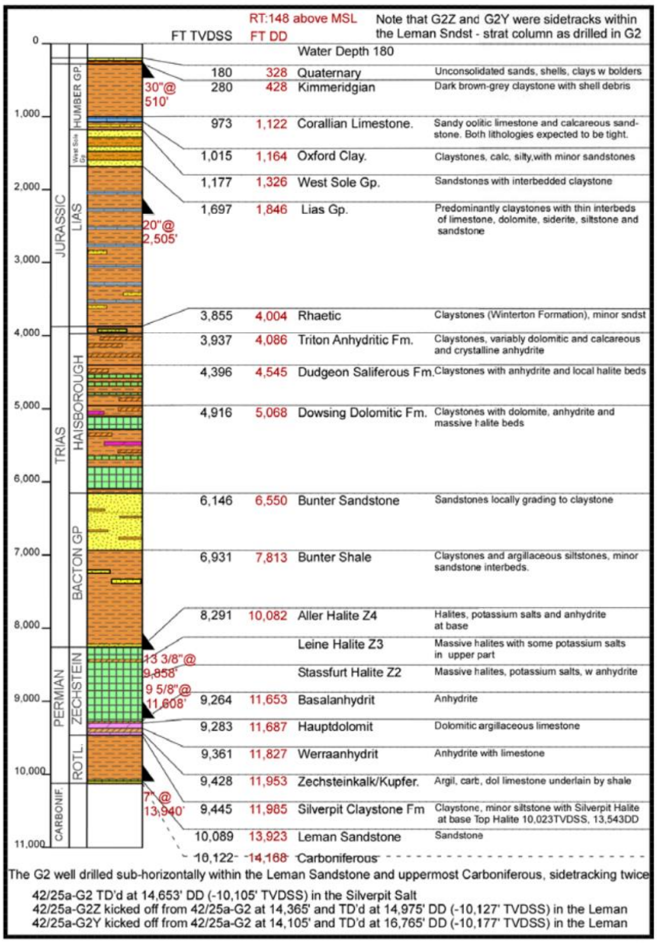


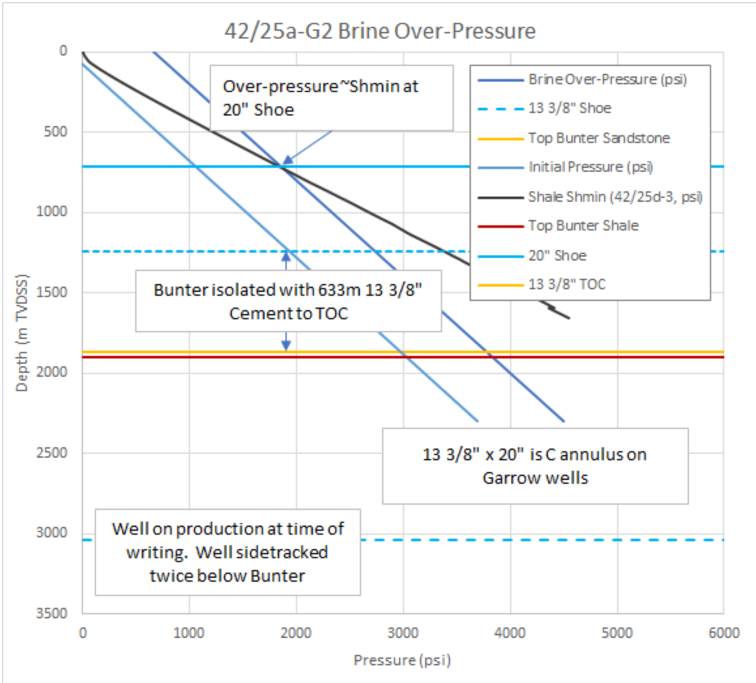

42/25a-G1 Brine Over-Pressure
Over-pressure~LOT at 20" Shoe
Bunter isolated with 618m 13 3/8" Cement to TOC
13 3/8" x 20" is C annulus on Garrow wells
Well on production at time of writing. Well sidetracked twice below Bunter
Brine Over-Pressure (psi)
13 3/8" Shoe
Top Bunter Sandstone
Initial Pressure (psi)
Shale Shmin (42/25d-3, psi)
Top Bunter Shale
20" Shoe LOT
20" Shoe
13 3/8" TOC
Depth (m TVDSS)
0
500
1000
1500
2000
2500
3000
Pressure (psi)
0
1000
2000
3000
4000
5000
6000

15.1.16 Garrow 42/25a-G2

- Brine over-pressure 800psi
- Isolation by 1157m 13 3/8" annular cement to TOC
- 13 3/8" x 20" annulus open above TOC
- Well status – development well on production

42/25a-G2/G2Z/G2Y (Garrow) Stratigraphic Column





15.2 43/21-2 13 3/8" CBL Log

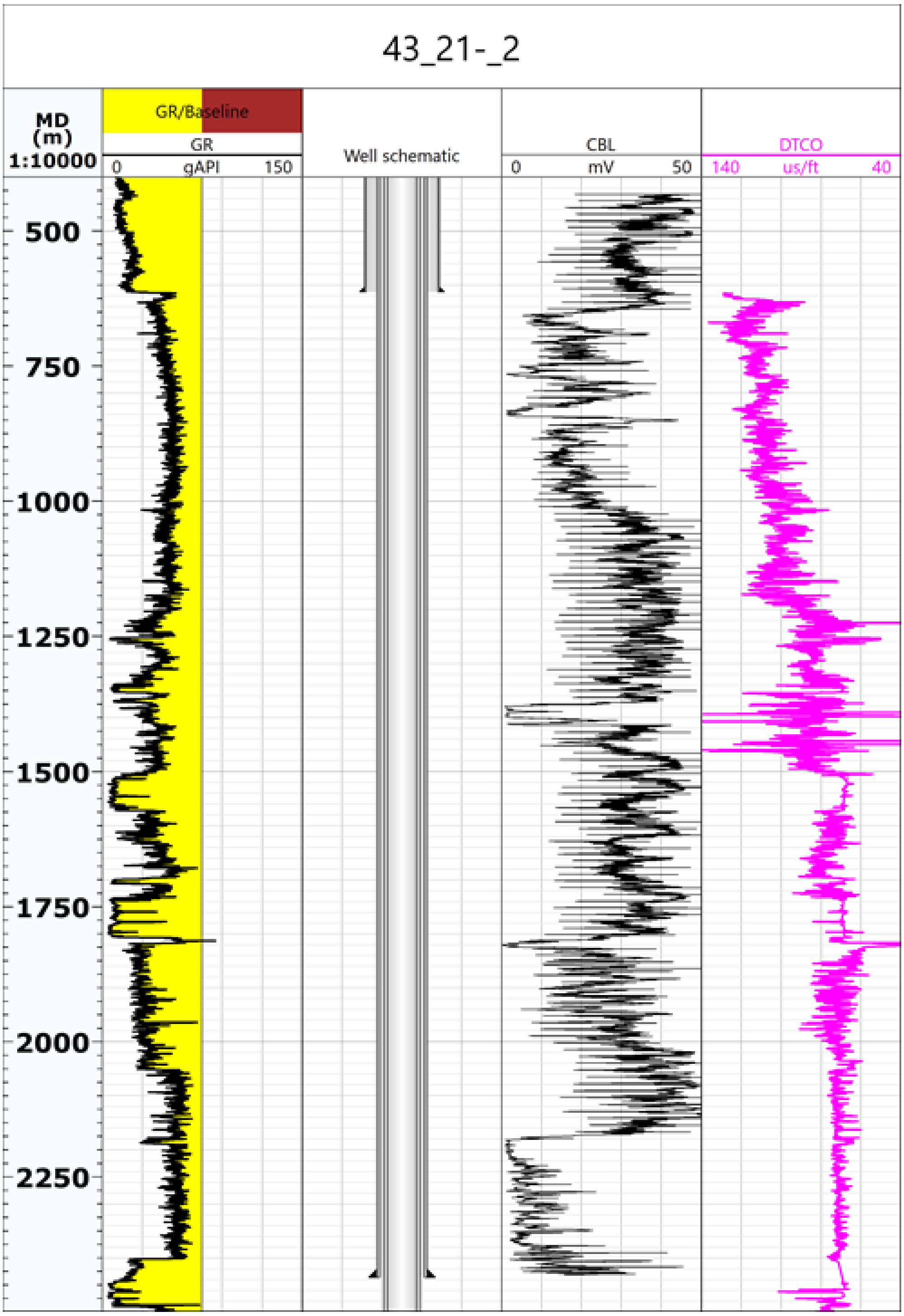


Figure 41 43/21-2 CBL