BTP-3 ACP MANAGEMENT PLAN

Validity Status	Rev. Number	Date	Description	Prepared by	Checked by	Approved by	Contractor Approval	Company Approval
				[redacted]				
EX-DE	01	26/02/24	Final Issue					
EX-DE	00	11/09/23	Final Issue					
Revision index								

eni australia

Project name

BLACKTIP OPERATIONS

Company identification

000036_DV_PR.D&C.0883.000

Job N. ___

Contractor identification

Contract ___

(Vendor logo and business name)

Vendor identification

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Order N...........................

Facility Name	Location	Scale	Sheet of Sheets
BLACKTIP	NORTHERN TERRITORY & WESTERN AUSTRALIA	1:1	1 / 38

Document Title

BLACKTIP-P3 ANNULUS CASING PRESSURE MANAGEMENT PLAN

Supersedes N.................

Superseded by N.............

Plant Area	Plant Unit

REVISION HISTORY

Rev.	Date	Nr. of sheets	Description
00	11/09/23	37	Final Issue
01	26/02/24	38	Final Issue C-annulus MAWOP & TTOC review

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1. INTRODUCTION.

1.1 Scope

This document provides the background history and guidance for managing the observed 20" x 13-5/8" casing annulus pressure in the Blacktip-P3 well. Leveraging from API RP 90-1 Annular Casing Pressure Management for Offshore Wells, the document seeks to detail the following:

- P3 Well history.
- Observation and nature of the observed casing pressure.
- Monitoring.
- Proposed diagnostic methods and frequency.
- MAASP and MAWOP determinations.
- Documentation & recoding.
- Risk Assessment.
- Implications for the production phase of the well
- Implications for the future abandonment of the well
- Contingency planning

This information has been collated to ensure that well integrity is maintained, and risks are managed to ALARP during the well life cycle.

1.2 Summary of Findings

Once the 20" x 13-5/8" casing sustained casing pressure (SCP) had been confirmed, a series of diagnostic tests were undertaken to determine the source and magnitude of the gas in the annulus. Tests were also undertaken to understand the annulus status, with respect to the cement bond, cement level and fluid levels.

A sample of gas taken from the annulus, confirmed a close match to the Mount Goodwin gas, which has a stratigraphic depth of 864 m MD to 1,145 m MD. A leak detection log was carried out using the VIVID SEAL acoustic logging tool string. The most prominent acoustic energy changes were observed within the Mount Goodwin (1,050 m-1,145 m), indicating movement of gas within this interval. Some minor acoustic events occurred between units A1_6 and Tern formation (1,150m-1,300m).

A ScanWell leak measurement survey was conducted with the well in production and the 20" x 13-5/8" casing annulus open. The measured stable flowrate was 6.35 kg/hr, which equates to 4.55 scf/min. The leak rate through the cement sheath was minor and less than the allowable API6A wellhead valve leak rate. The fluid level was also measured to be 5 m below the wellhead datum.

Tests confirmed the source as the shallow Mount Goodwin reservoir, with the cause being a cement micro annulus that allowed pressure transference, with a wellhead pressure of 670 psi+/- and a minor flowrate. This has allowed the risks to be quantified and mitigations to be put in place, allowing the well to be produced safely.

1.3 Blacktip Development

The Blacktip gas field in WA-33-L in the Bonaparte Gulf of Western Australia was discovered in 2001. The field is located 300 km off the southwest of Darwin in Western Australian waters. The field map is shown in Figure 1.1.

The Blacktip WHP is an unmanned six-slot wellhead platform and is not equipped with any processing facilities. The platform is located over the Blacktip Field in approximately 50 m of water. Currently there are three (3) production wells on the WHP.

A key feature of the design is that no processing takes place on the WHP. The reservoir fluids are sent onshore via the 17" ID GEP to the YGP for processing. This feature simplifies the WHP design considerably and allows a minimum facilities approach with clear benefits in reducing manning requirements to a minimum.

No automatic blowdown facility is included in the design; pipe work on the WHP is designed to full reservoir closed-in tubing head pressure (CITHP) with a maintenance vent for manual depressurisation.

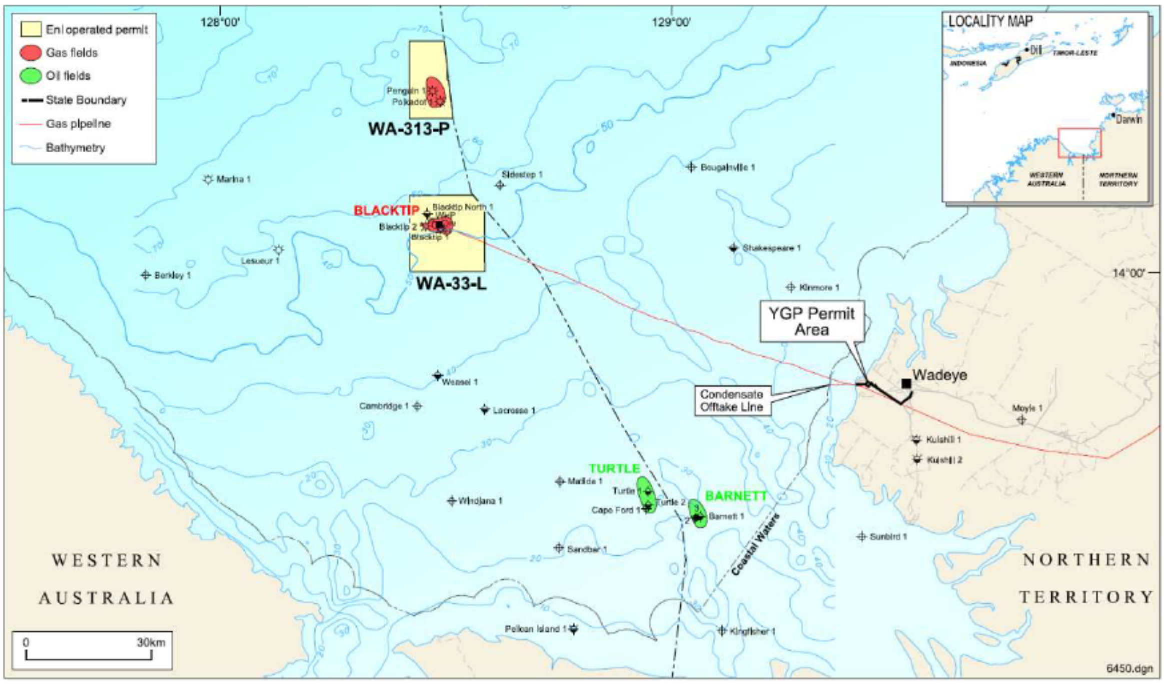


Figure 1.1: Blacktip Field Map

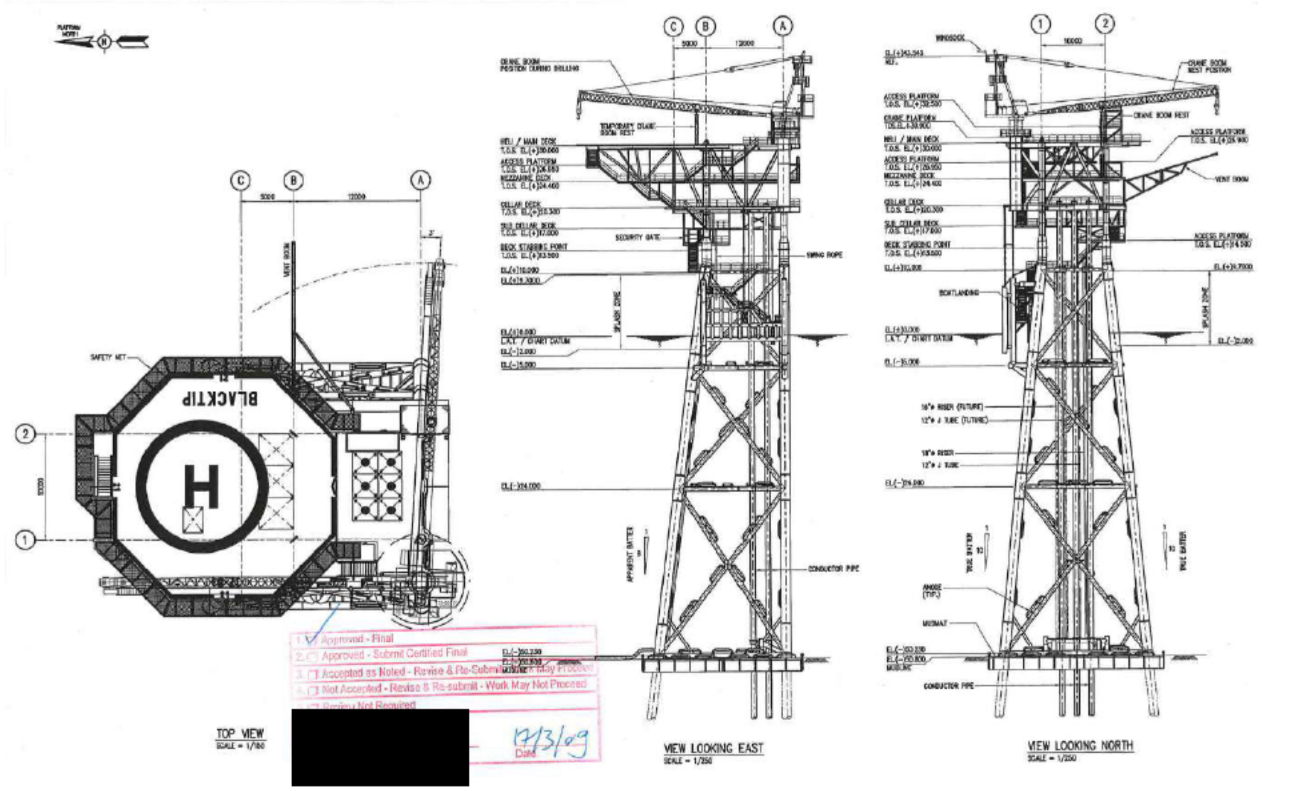


Figure 1.2: Schematic of Wellhead Platform

1.4 P3 Well Information

1.4.1 Well Details

Blacktip P3 was drilled and completed as a gas production well by the Valaris V107 jackup rig. The well was spudded on the 16 December 2022 and drilled to a total depth of 3,529 m MDRT on 19th of January 2023. The well was completed, and production flow tested on 30th May 2023.

Well:	Blacktip-P3	Operator:	ENI (100%)
Well Type:	Development	Partners:	None
Basin:	Bonaparte	Purpose:	Development Well
Tenement:	WA-33-L		
Objective:	Keyling Sst's (A2, A4)	Surface Location	
Status:	Completed as a gas producer	Latitude:	13º 53' 41.734" South
Rig on Location: Rig Released:	04/12/22 @ 10:30 hr 30/05/23 @ 22:30 hr	Longitude:	128º 29' 02.749" East
		Easting:	444 261.34 m
		Northing:	8 463 834.03 m
		TD Location	
		Latitude:	13º 54' 18.97" South
Total Depth:	3,529.0 mMDRT; 3,200.17 m TVDSS	Longitude:	128º 28' 52.53" East
RT Elevation:	57.01 m above LAT	Easting:	443 956.99 m
Water Depth:	50.8 m below LAT	Northing:	8 462 689.34 m
Drilling Rig & Type:	Valaris 107 Jackup KFELS MOD V-B	Datum:	GDA94 UTM Zone 52

1.4.2 Well Construction History

The 30” conductor casing was pre-set in 2009 at a depth of 186 m MD/186 m TVDRT.

The 26” section was drilled to 955.0 m MDRT/ 881.25 m TVDSS and the 20” 133 ppf K-55, Tenaris Blue casing set and cemented at 949.39 m MD/876.15 m TVDSS. TTOC for the 20” casing is seabed at 50 m MDRT.

The 17-1/2” hole was drilled with PERFLEX WBM @ 1.15 sg – 1.20 sg to 2,352.55 m MDRT / 2,078.91 m TVDSS and the 13-5/8" 88.2#, L-80, Tenaris Blue casing set and cemented at 2,345.24 m MD/2,078.91 m TVDSS. TTOC for the 13-5/8” casing is at 644 m MDRT, which is 150 m inside the 20” casing shoe. The cement was not logged for height or quality of seal.

The 12-1/4” hole was drilled with PERFLOW WBM 1.10 -1.15 sg to TD at 2,986 m MDRT/2,675.52 m TVDSS. The 9-5/8" 53.5# L-80, 13Cr, Tenaris Blue casing liner set and cemented with the shoe at 2,985 m MDRT/2,673 m TVDSS with the liner top at 2,243.52 m MDRT/1,991.46 m TVDSS. The liner was cemented to the liner top at 2,243.52 m MDRT. The cement was logged using a USIT and confirmed to be at the TOL.

The 8-1/2” hole was drilled with PERFLOW WBM at 1.15 – 1.19 sg to TD at 3,529 m MDRT / 3,200 m TVDSS. The 7’’ 29# L-80, 13Cr, Tenaris Blue casing liner set and cemented with the shoe at 3,525.25 m MD / 3,197.51 m TVDSS with the liner top 2,942 m MDRT / 2,632.91 m TVDSS. The liner was cemented with a planned TOC at the liner top 2,942 m MDRT. The cement was logged using a USIT and TOC was confirmed to be at the 3,008 m MDRT.

The well was then completed with a 7” 13% Cr tubing completion with five (5) zonal isolation packers and an upper completion packer.

No pressure had been recorded in the casing annuli from the 7th of January through to the 13th of February. During the completion installation operations between 25th of January 2023 and 24th of February 2023 the 20” x 13-5/8” casing annulus pressure was observed to increase to 660 psi. This initiated an annulus pressure investigation which has resulted in the writing of this casing annulus pressure management plan.

1.4.3 Well Details

- Hole Sections

Hole Size (“)	Depth (m MDRT)	Depth (m TVDSS)
36	Conductor driven	Conductor driven
26	955.00	881.25
17-1/2	2,352.55	2,085.20
12-1/4	2,986.00	2,675.52
8-1/2	3,529.00	3,200.17

- Casing Details - Depths

Casing Size (")	Casing Grade / weight	Top Depth (mMDRT/TVDSS)	Shoe Depth	
			m MDRT	m TVDSS
30	1.5" WT X-52 RL-4S	35.33 / 35.33	186.56	129.55
20	133 ppf K55 Quick Seal DPLS	35.10 / 35.10	949.39	876.15
13-5/8	88.2 ppf L80 TSH Blue	34.80 / 34.80	2,345.24	2,078.91
9-5/8	53.5 ppf L80 13 Cr TSH Blue	2,243.52 / 1,991.46	2,982.83	2,672.45
7	29 ppf L80 13 Cr TSH Blue DPLS & 29 ppf L80 13 Cr TSH Blue	2,942 / 2,632.91	3,526.25	3,196.56

- Casing Details - Performance

Casing Size (in)	Specification	Setting Depths	Performance		
		M MDRT	Burst psi	Collapse psi	Tension kips
30" Conductor String (Hammered 2009)					
30" Casing	1.5" WT, 310 lb/ft, X-52, RL4S	WHD - 186.56	3,000	1,581	4,738
20" Surface Casing String					
20" Casing	133# K55 Quick seal DPLS	WHD - 949.39	3,060	1,500	2,125
13-5/8" Production Casing String					
13-5/8" Casing	88.2# L-80 Tenaris Blue	WHD – 2,345.24	6,420	3,980	2,042
9-5/8" Production Liner					
9-5/8" Liner	53.5#, L-80, 13Cr, Tenaris Blue	2,243.52 – 2,982.83	7,930	6,620	1,244
7" Production Liner					
7" Liner	29#, L-80, 13Cr, Tenaris Blue	2,942 – 3,526.25	8,160	7,030	676

- Cementing Details

Cement Summary	Hole Section			
	26" x 20" Casing	17-1/2" x 13-5/8" Casing	12-1/4" x 9-5/8" Liner	8-1/2" x 7" Liner
Lead Slurry Weight	1.49 sg	1.43 sg	1.43 sg	1.43 sg
Tail Slurry Weight	1.89 sg	1.89 sg	1.89 sg	1.89 sg
Tail length	150 m	150 m	100 m	100 m
TOC	50 m MDRT Seabed	TTOC 644 m MDRT	TOL 2,243.52 m MDRT Logged	3008 m MDRT Logged

- FIT/LOT

Type	Depth (m TVDSS)	EMW (sg)	Comments
FIT	876.15	1.40*	See note below on minimum formation strength assumption
FIT	2,078.88	1.50	1,206 psi on surface. MW 1.10 sg

*The 20" shoe formation strength has been assessed by the Eni corporate subsurface team using a post-drilling PPFG study and a shoe strength of 1.6 sg (2142 psi) has been assessed to be the minimum fracture gradient.

- Drilling Fluids

Mud Type	Depth Interval (mMDRT)	MW (sg)	ECD (sg)	Comments
Gel / Polymer	186.56-955.0	1.03 – 1.08	-	N/A – no APWD
PERFLEX WBM	955.0-2,352.5	1.15 – 1.20	1.20	
PERFLOW WBM	2,352.5-2,986.0	1.10 -1.20	1.19	
PERFLOW WBM	2,986.0-3,529.0	1.15 - 1.19	1.23	

1.4.4 Geology and Hydrocarbon Shows

The table below details the formations drilled and hydrocarbon shows encountered on the Blacktip P3 well.

Table 1.1: Formation depths and pressures

Mud Type	mMDRT	mTVDSS	Comments
Seabed	107.81	50.8	N/A – no APWD
Base Cretaceous	457.00	399.96	
Top Mount Goodwin	864.56	797.80	
Goodwin A1 Sandstone	1,050.50	966.72	MDT Formation pressure 1,432 psi @ 985.5m TVD SS
Tern Formation	1,340.20	1,217.28	
Dombey Formation	1,419.60	1,285.30	
Cape Hay Formation	1,428.20	1,292.67	
Pearce Limestone	1,798.00	1,609.68	
Torrens Shale	1,812.10	1,621.77	
Torrens Sand	1,836.90	1,643.05	
Fossil Head Shale	1,860.00	1,662.88	
Fossil Head Sand	1,867.90	1,669.66	MDT Formation pressure 2,621 psi.
Keyling Formation	2,392.16	2,119.25	MDT Formation pressure 2,818 psi.
Treachery Formation	3,146.87	2,831.27	
TD	3,529.00	3200.17	
Seabed			

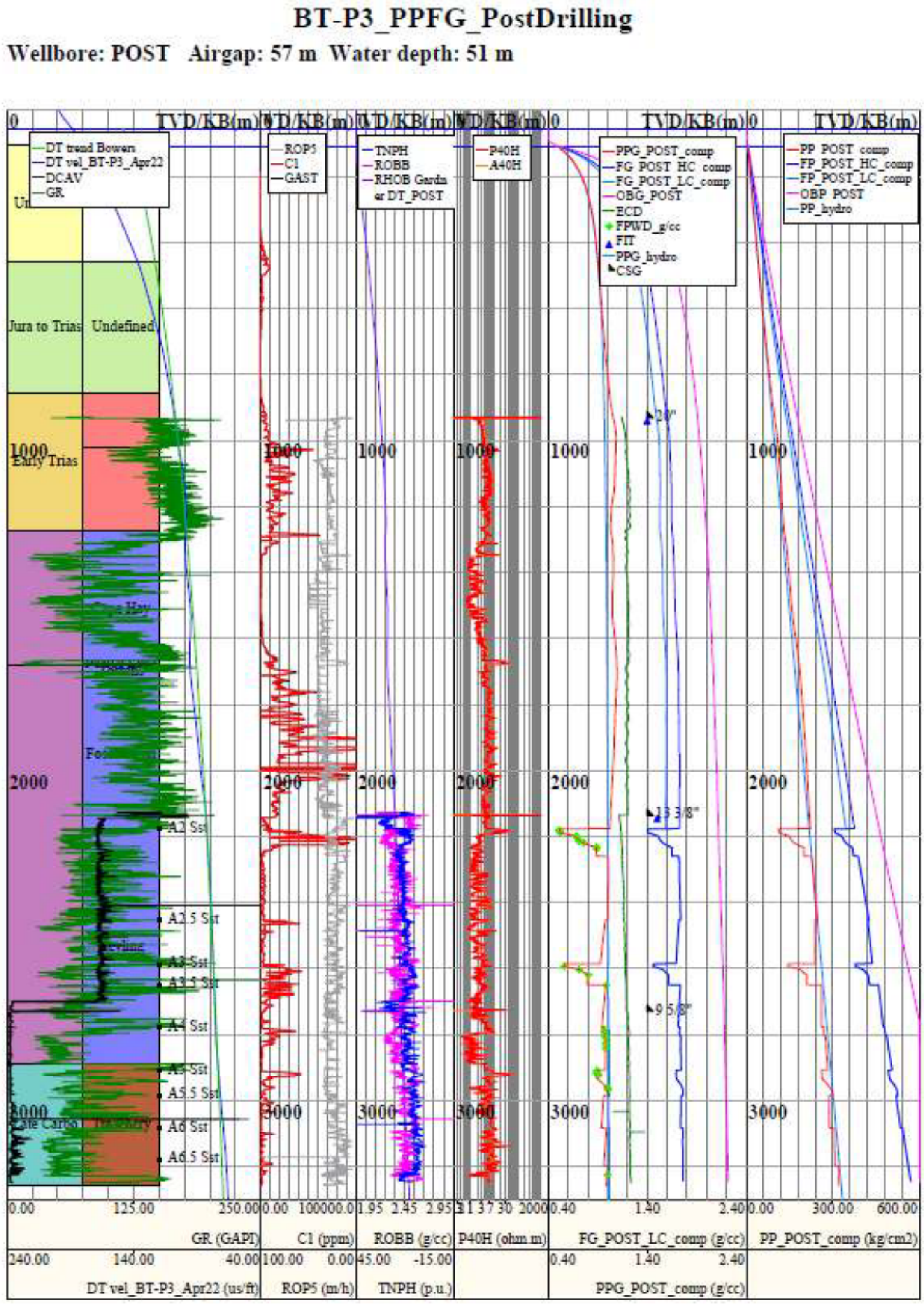


Figure 1.3: PPFG Schematic

1.4.5 Well Schematic (Casing, Completion & Wellhead)

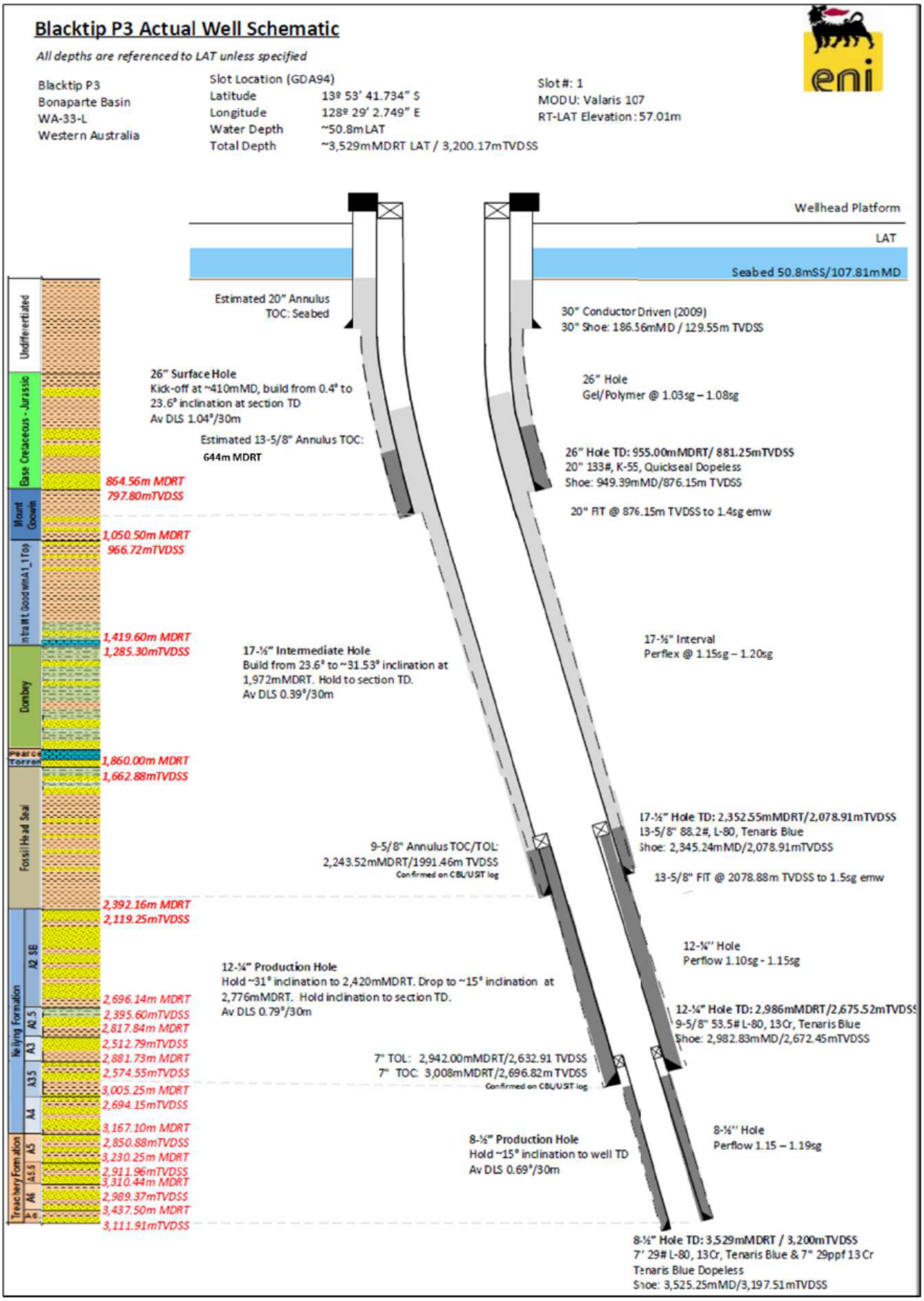
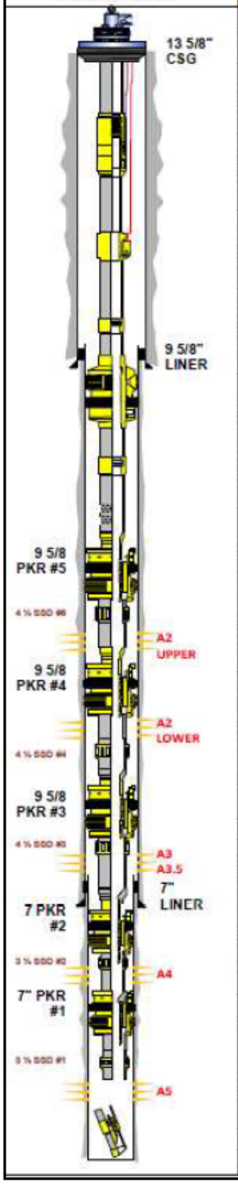


Figure 1.4: As Built Casing Schematic

AS RUN SCHEMATIC — WELL : P3 — FIELD: BLACKTIP — PLATFORM : BLACKTIP — PERMIT WA33L

Rig Name	Rig Type	Annulus Fluid	Annulus Fluid Wt	RTE (m)	Max Dog Leg	Top of WH to RTE (m)	Water Depth (m)	Max Dev	Rev	Date
Valaris 107	Jack-Up	Inhibited NaCl	1.1 SG	57.01	2.69deg/30m	33.1	50.8	31deg	11	16-May-23

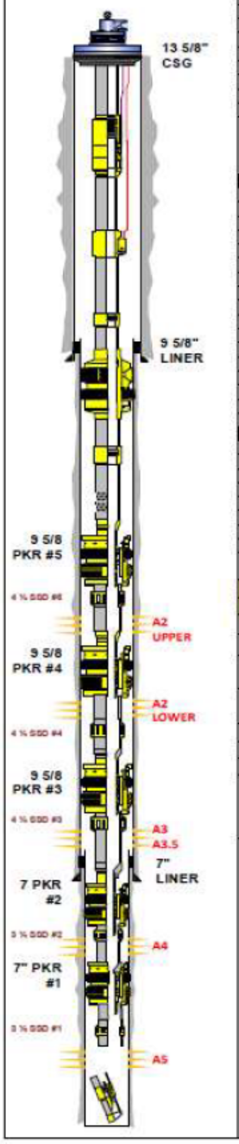
Size (in)	Weight (lb/ft)	Connection	Material	Type	Top MDRTm	Bot MDRTm	ID (in)	OD (in)	Top TVDRTm	Bot TVDRTm	Drift (in)	Mud Wht (SG)	Csg Test Pressure (psi)
20"	133.00	TSH Blue-QS DPLS	K55	Csg	35.27	949.39	18.73	20	35.27	933.16	18.542	1.05	2000
13-5/8"	88.20	TSH BLUE	L80	Csg	34.80	2345.24	12.375	13 5/8	31.56	2153.04	12.250	1.20	3650
9-5/8"	53.50	TSH BLUE	13CR80	Liner	2243.50	2982.83	8.535	9 5/8	2048.47	2729.46	8.50	1.15	2900
7"	29.00	TSH BLUE	13CR80	Liner	2942.00	3526.25	6.184	7	2688.95	3253.56	6.059	1.18	3200



Item No	Assy No	Description	Supplier / Vendor	Top Depth MDRTm	Btm Depth MDRTm	Top Depth TVDRT m	Length (m)	OD (in)	ID (in)	Drift (in)
	ENI-UC-TH-22-01	Tubing Hanger	TFMC	33.06	34.40	33.06	1.35	18.580	6.095	6.059
		Pup Jt, 7-29.00 TSH-BLUE	TENARIS	34.40	37.82	34.40	3.42	7.000	6.086	6.059
		TUBING,7-29.00 TSH-BLUE	TENARIS	37.82	162.77	37.82	124.96	7.000	6.086	6.059
	ENI-UC22-TRSV-01	Pup Jt, 7-29.00 TSH-BLUE	TENARIS	162.77	165.72	162.77	2.95	7.000	6.086	6.059
15.1		FLO CPLG,FN,60,13CR,7-29 TSH BLUE X 7-29 VAMTOP,B-B	HAL	165.72	167.25	165.72	1.53	7.698	6.085	6.059
15.2		SP(TM) Tubing-Retrievable Safety Valve,SP-ENH Valve Model,7	HAL	167.25	169.82	167.25	2.57	8.900	5.875	5.865
15.3		FLO CPLG,FN,60,13CR,7-29 VAMTOP X 7-29 TSH BLUE ,B-P	HAL	169.82	171.15	169.82	1.34	7.698	6.085	6.059
		Pup Jt, 7-29.00 TSH-BLUE	TENARIS	171.15	173.09	171.15	1.94	7.070	6.086	6.059
		TUBING,7-29.00 TSH-BLUE	TENARIS	173.09	2,134.07	173.09	1960.98	7.070	6.086	6.059
	ENI-UC-PDHG-22-01	Pup Jt, 7-29.00 TSH-BLUE	TENARIS	2,134.07	2,137.03	1954.59	2.95	7.070	6.086	6.059
3.1		CPLG,7-29.00 TSH BLUE X 7-29.00 VAM21,13CR,80MY	HAL	2,137.03	2,137.34	1957.13	0.32	7.697	6.106	6.059
3.2 / 3.4		OPSIS PDHG DUAL SENSOR, TUBING-ANNULUS GAUGE MANDREL ,7-	HAL	2,137.34	2,138.69	1957.40	1.34	8.102	5.890	5.843
3.3		COMB ADPTR,7-29.00 VAM21 Box x 7-29.00 TSH BLUE Pin 7.713 6.165	HAL	2,138.69	2,139.16	1958.55	0.47	7.703	6.165	6.509
		Pup Jt, 7-29.00 TSH-BLUE	TENARIS	2,139.16	2,141.01	1958.96	1.86	7.070	6.086	6.059
		TUBING,7-29.00 TSH-BLUE	TENARIS	2,141.01	2,315.85	1960.55	174.84	7.070	6.086	6.059
	ENI-UC-22-AHC-01	Pup Jt, 7-29.00 TSH-BLUE	TENARIS	2,315.85	2,318.74	2110.77	2.89	7.070	6.086	6.059
4.1		LN,5.843,S-1,13CR,7-29.00 TSH BLUE,B-P	HAL	2,318.74	2,319.19	2113.26	0.45	7.697	5.843	5.833
		Pup Jt, 7-29.00 TSH-BLUE	TENARIS	2,319.19	2,321.13	2113.64	1.94	7.000	6.086	6.059
		Pup Jt, 7-29.00 TSH-BLUE	TENARIS	2,321.13	2,323.98	2115.31	2.86	7.000	6.086	6.059
5		PKR,AHC,9 5/8,47-53.5,7-29.00 TSH BLUE	HAL	2,323.98	2,327.11	2117.77	3.13	8.350	5.970	5.833
		Pup Jt, 7-29.00 TSH-BLUE	TENARIS	2,327.11	2,329.05	2120.46	1.93	7.070	6.086	6.059
		TUBING,7-29.00 TSH-BLUE	TENARIS	2,329.05	2,340.71	2122.12	11.66	7.070	6.086	6.059
	ENI-UC-22-LN-01	Pup Jt, 7-29.00 TSH-BLUE	TENARIS	2,340.71	2,343.65	2132.14	2.93	7.070	6.086	6.059
6		LN,5.625,RPT,13CR,7.00-26.00 TS-BLUE,B-P 7.697 5.625	HAL	2,343.65	2,344.18	2134.66	0.53	7.697	5.625	5.620
		Pup Jt, 7-29.00 TSH-BLUE	TENARIS	2,344.18	2,346.11	2135.12	1.93	7.070	6.086	6.059
		PERFORATED JOINT, 7-29.00 TSH-BLUE	TENARIS	2,346.11	2,357.89	2136.78	11.78	7.070	6.086	6.059
	ENI-UC-22-SA-01	Pup Jt, 7-29.00 TSH-BLUE	TENARIS	2,357.89	2,360.82	2146.89	2.94	7.070	6.086	6.059
8		REDC ADPTR,7-29.00 TSH BLUE X 4 1/2-12.60 TSH Blue Pin	HAL	2,360.82	2,361.23	2149.42	0.41	7.697	3.979	3.833
		Pup Jt,4 1/2-12.60 TS-BLUE	TENARIS	2,361.23	2,363.18	2149.76	1.95	4.500	3.894	3.833
9.1A		COMB ADPTR,4 1/2-12.60 TSH BLUE X 4 1/2-	HAL	2,363.18	2,363.50	2151.44	0.32	4.979	3.906	3.833
9.2A		LOCTR,NO-GO,4 1/2-12.60 VAMTOP X 5 1/2	HAL	2,363.50	2,363.95	2151.72	0.45	6.560	3.903	3.853
9.3A		SEAL UNIT EXT,6.000 X 44.43,5 1/2-17.00	HAL	2,363.95	2,364.97	2152.10	1.02	5.945	4.872	4.842
9.4A/9.3B		SEAL ASSY,6.000,5 1/2-17 VAMTOP SPCL,B-P 6.018 4.872	HAL	2,364.97	2,365.47	2152.98	0.51	6.018	4.872	4.842
9.4A/9.3B		SEAL ASSY,6.000,5 1/2-17 VAMTOP SPCL,B-P 6.018 4.872	HAL	2,365.47	2,365.98	2153.41	0.51	6.018	4.872	4.842
9.5A/9.4B		MULE SHOE,SELF ALIGN,5 1/2-17 VAMTOP BOX	HAL	2,365.98	2,367.05	2153.85	1.07	5.960	4.872	4.842
		9 5/8" Middle Completion Packer #5								
10.1A/10.1B	ENI-MC-22-9 5/8 VCH SBE-01	VCH PKR,9 5/8,47-53.5,6.000	HAL	2,363.33	2,365.74	2151.57	2.41	8.300	6.000	5.990
10.2A		Bottom Sub for Versa-Trieve(R) Packer,VBA/VCA/VCH TYPE,7 15/16-6	HAL	2,365.74	2,365.89	2153.64	0.15	8.300	6.000	5.990
10.3A		Sealbore Extension,72.05 in. Length,13Cr Matl,7-29 JFEBEAR Box-	HAL	2,365.89	2,367.59	2153.77	1.70	7.850	6.000	5.990
10.4A		Reducing Adapter,7-29 JFEBEAR Box x 4 1/2-12.6 TSH BLUE Pin,7.635	HAL	2,367.59	2,368.02	2155.23	0.43	7.635	3.941	3.833
11.1		COMB ADPTR,4 1/2-12.60 TSH BLUE X 4 1/2- 4.979 3.906	HAL	2,368.02	2,368.34	2155.60	0.32	4.979	3.906	3.833
11.2		SSD,3.813,4 1/2-12.60 VAMTOP,B-P,13CR	HAL	2,368.34	2,369.63	2155.88	1.29	5.600	3.813	3.803
11.3		COMB ADPTR,4 1/2-12.60 VAMTOP X 4 1/2-12 4.967 3.903	HAL	2,369.63	2,369.92	2156.99	0.29	4.967	3.906	3.833
		Pup Jt,4 1/2-12.60 TS-BLUE	TENARIS	2,369.92	2,371.86	2157.23	1.95	4.500	3.894	3.833
		TUBING,4 1/2-12.60 TS-BLUE	TENARIS	2,371.86	2,385.35	2158.91	13.48	4.967	3.894	3.833
		BL NIP,BN,240.0,13CR,4 1/2-12.60,,BOT 5.030 3.848	HAL	2,385.35	2,403.37	2170.49	18.02	5.030	3.848	3.833
	ENI-MC-22-6in SA-03	BL NIP,BN,240.0,13CR,4 1/2-12.60,,BOT 5.030 3.848	TENARIS	2,403.37	2,409.48	2185.98	6.11	4.987	3.894	3.833
9.1B Option		Combination Adapter,4 1/2-12.60 TSH BLUE Box x 4 1/2-12.60	HAL	2,409.48	2,409.80	2191.23	0.32	4.979	3.906	3.833
9.2B Option		Versa Latch Seal Unit Locator Assembly,6 inch Seal Bore ID- Min,4 1/2-	HAL	2,409.80	2,410.70	2191.50	0.90	6.813	3.903	3.833
9.4A/9.3B		RTR Premium Seal Unit,6 in. Seal Bore ID-Min,13% Chrome Matl,	HAL	2,410.70	2,411.21	2192.27	0.51	6.018	4.872	3.833
9.4A/9.3B		RTR Premium Seal Unit,6 in. Seal Bore ID-Min,13% Chrome Matl,	HAL	2,411.21	2,411.71	2192.71	0.51	6.018	4.872	3.833
9.5A/9.4B		Self-Aligning Muleshoe Guide,6.000 in. Seal Bore ID-Min,5 1/2-17.00	HAL	2,411.71	2,412.78	2193.14	1.07	5.980	4.872	3.833
				Top A2 Upper Perf (MDRTm)	2391.50				Bot A2 Upper Perf (MDRTm)	2406.50
		9 5/8" Middle Completion Packer #4								
10.1A/10.1B	ENI-MC-6-VCH-04	VCH PKR,9 5/8,47-53.5,6.000	HAL	2,409.59	2,411.99	2191.32	2.40	8.300	6.000	5.990
10.2B		SUB,BOT,7 15/16-6 STUB AC X 7-29.00,,AYJ 8.300 6.000	HAL	2,411.99	2,412.27	2193.39	0.28	8.300	6.000	5.990
10.3B		PUP JT,7-29.00 TSH BLUE X 24.0,HAL L-80 7.070 6.086	HAL	2,412.27	2,412.65	2193.62	0.38	7.850	6.000	5.990
10.4B		REDC ADPTR,7-29.00 TSH BLUE 7.697 3.919	HAL	2,412.65	2,413.06	2193.95	0.41	7.635	3.941	3.833
		BL NIP,BN,240.0,13CR,4 1/2-12.60,,BOT 5.030 3.848	HAL	2,413.06	2,431.08	2194.30	18.02	5.030	3.848	3.833
	ENI-MC-22-SSD-01	Pup Jt,4 1/2-12.60 TS-BLUE	TENARIS	2,431.08	2,433.02	2209.36	1.93	4.500	3.894	3.833
11.1		COMB ADPTR,4 1/2-12.60 TSH BLUE X 4 1/2- 4.979 3.906	HAL	2,433.02	2,433.34	2211.07	0.32	4.979	3.906	3.833
11.2		SSD,3.813,4 1/2-12.60 VAMTOP,B-P,13CR	HAL	2,433.34	2,434.63	2211.35	1.29	5.600	3.813	3.803
11.3		COMB ADPTR,4 1/2-12.60 VAMTOP X 4 1/2-12 4.967 3.903	HAL	2,434.63	2,434.92	2212.50	0.29	4.967	3.906	3.833
		Pup Jt,4 1/2-12.60 TS-BLUE	TENARIS	2,434.92	2,436.86	2212.75	1.95	4.500	3.894	3.833
		TUBING,4 1/2-12.60 TS-BLUE	TENARIS	2,436.86	2,590.03	2214.48	153.16	4.967	3.894	3.833
	ENI-MC-22-6in SA-02	Pup Jt,4 1/2-12.60 TS-BLUE	TENARIS	2,590.03	2,591.97	2352.46	1.95	4.987	3.894	3.833
9.1B Option		Combination Adapter,4 1/2-12.60 TSH BLUE Box x 4 1/2-12.60	HAL	2,591.97	2,592.30	2354.27	0.32	4.979	3.906	3.833
9.2B Option		Versa Latch Seal Unit Locator Assembly,6 inch Seal Bore ID- Min,4 1/2-	HAL	2,592.30	2,592.97	2354.57	0.67	6.813	3.903	3.833
9.4A/9.3B		RTR Premium Seal Unit,6 in. Seal Bore ID-Min,13% Chrome Matl,	HAL	2,592.97	2,593.48	2355.19	0.51	6.018	4.872	3.833
9.4A/9.3B		RTR Premium Seal Unit,6 in. Seal Bore ID-Min,13% Chrome Matl,	HAL	2,593.48	2,593.99	2355.66	0.51	6.018	4.872	3.833
9.5A/9.4B		Self-Aligning Muleshoe Guide,6.000 in. Seal Bore ID-Min,5 1/2-17.00	HAL	2,593.99	2,595.06	2356.13	1.07	5.980	4.872	3.833
				Top A2Lower Perf (MDrtm)	2416.50				Bot A2 Lower Perf (MDRTm)	2426.50
		9 5/8" Middle Completion Packer #3								
10.1A/10.1B	ENI-LC-22-9 5/8 VCH-01	VCH PKR,9 5/8,47-53.5,6.000	HAL	2,592.15	2,594.56	2354.43	2.41	8.300	6.000	5.990
10.2B		SUB,BOT,7 15/16-6 STUB AC X 7-29.00,,AYJ 8.300 6.000	HAL	2,594.56	2,594.83	2356.66	0.28	8.300	6.000	5.990
10.3B		PUP JT,7-29.00 TSH BLUE X 24.0,HAL L-80 7.070 6.086	HAL	2,594.83	2,595.21	2356.92	0.38	7.070	6.086	5.990
10.4B		REDC ADPTR,7-29.00 TSH BLUE 7.697 3.919	HAL	2,595.21	2,595.62	2357.28	0.41	7.697	3.919	
11.1		COMB ADPTR,4 1/2-12.60 TSH BLUE X 4 1/2- 4.979 3.906	HAL	2,595.62	2,595.94	2357.65	0.32	4.979	3.906	3.833
11.2		SSD,3.813,4 1/2-12.60 VAMTOP,B-P,13CR	HAL	2,595.94	2,597.16	2357.96	1.22	5.600	3.813	3.803
11.3		COMB ADPTR,4 1/2-12.60 VAMTOP X 4 1/2-12 4.967 3.903	HAL	2,597.16	2,597.45	2359.10	0.29	4.967	3.906	3.833
		Pup Jt,4 1/2-12.60 TS-BLUE	TENARIS	2,597.45	2,599.39	2359.38	1.95	4.500	3.894	3.833
		TUBING,4 1/2-12.60 TS-BLUE	TENARIS	2,599.39	2,830.03	2361.18	230.63	4.967	3.894	3.833

Figure 1.5: As Built Completion Schematic 1a

AS RUN SCHEMATIC



WELL : P3 FIELD: BLACKTIP PLATFORM : BLACKTIP PERMIT WA33L

Rig Name	Rig Type	Annulus Fluid	Annulus Fluid Wt	RTE (m)	Max Dog Leg	Top of WH to RTE (m)	Water Depth (m)	Max Dev	Rev	Date
Valaris 107	Jack-Up	Inhibited NaCl	1.1 SG	57.01	2.69deg/30m	33.1	50.8	31deg	11	16-May-23

Size (in)	Weight (lb/ft)	Connection	Material	Type	Top MDRTm	Bot MDRTm	ID (in)	OD (in)	Top TVDRTm	Bot TVDRTm	Drift (in)	Mud Wht (SG)	Csg Test Pressure (psi)
20"	133.00	TSH Blue-QS DPLS	K55	Csg	35.27	949.39	18.73	20	35.27	933.16	18.542	1.05	2000
13-5/8"	88.20	TSH BLUE	L80	Csg	34.80	2345.24	12.375	13 5/8	31.58	2153.04	12.250	1.20	3650
9-5/8"	53.50	TSH BLUE	13CR80	Liner	2243.50	2982.83	8.535	9 5/8	2048.47	2729.46	8.50	1.15	2900
7"	29.00	TSH BLUE	13CR80	Liner	2942.00	3526.25	6.184	7	2688.95	3253.56	6.059	1.18	3200

Item No	Assy No	Description	Supplier / Vendor	Top Depth MDRTm	Btm Depth MDRTm	Top Depth TVDRT m	Length (m)	OD (in)	ID (in)	Drift (in)
		BL NIP,BN,240.0,13CR,4 1/2-12.60,,BOT 5.030 3.848	HAL	2,830.03	2,860.07	2581.56	30.04	5.030	3.848	3.833
		TUBING,4 1/2-12.60 TS-BLUE	TENARIS	2,860.07	2,897.66	2610.60	37.59	4.967	3.894	3.833
		BL NIP,BN,240.0,13CR,4 1/2-12.60,,BOT 5.030 3.848	HAL	2,897.66	2,921.69	2646.93	24.03	5.030	3.848	3.833
		TUBING,4 1/2-12.60 TS-BLUE	TENARIS	2,921.69	2,992.74	2670.16	71.05	4.967	3.894	3.833
	ENI-LC-22-3.88-SA-02	Pup Jt,4 1/2-12.60 TS-BLUE	TENARIS	2,992.74	2,995.69	2738.84	2.95	4.500	3.894	3.833
13.1		Combination Adapter,4 1/2-12.60 TSHBLUE Box x 4 1/2-15.10 VAM-FJL	HAL	2,995.69	2,996.01	2741.69	0.33	5.765	3.868	3.833
13.2		Versa Latch Seal Unit Locator Assembly,3.88 inch Seal Bore ID-Min,4	HAL	2,996.01	2,996.99	2742.00	0.98	4.545	2.940	2.900
13.3		RTR Premium Seal Unit,3.88 in. Seal Bore ID-Min,13% Chrome Matl,	HAL	2,996.99	2,997.47	2742.94	0.49	3.864	2.940	2.900
13.3		RTR Premium Seal Unit,3.88 in. Seal Bore ID-Min,13% Chrome Matl,	HAL	2,997.47	2,997.96	2743.41	0.49	3.864	2.940	2.900
13.4		SELF-ALIGNING MULESHOE GUIDE, 3.880, 3 1/2-9.20 VAMTOP, BOX	HAL	2,997.96	2,998.87	2743.88	0.91	3.864	2.940	2.867
			Top of A3 Perf (MDRTm)	2830.00				Bot of A3 Perf (MDRTm)		2836.00
			Top of A3 Perf (MDRTm)	2840.00				Bot of A3 Perf (MDRTm)		2854.00
			Top of A3.5 Perf (MDRTm)	2900.00				Bot of A3.5 Perf (MDRTm)		2906.00
			Top of A3.5 Perf (MDRTm)	2911.00				Bot of A3.5 Perf (MDRTm)		2918.00
		7" Middle Completion Packer #2								
14.1	ENI-LC-22-7 VCH-02	Versa-Trieve(R) Retrievable Sand Control Packer VCH TYPE 7 in. 26-	HAL	2,996.11	2,998.35	2742.10	2.24	6.015	3.880	3.870
14.2		Bottom Sub for Versa-Trieve(R) Packer,VCH TYPE,5 13/32-8 STUB AC	HAL	2,998.35	2,998.80	2744.26	0.45	5.820	3.880	3.870
		Pup Jt,4 1/2-12.60 TS-BLUE	TENARIS	2,998.80	3,001.75	2744.70	2.95	4.500	3.894	3.870
15.5		Reducing Adapter,4 1/2-12.60 TSH BLUE Box x 3 1/2- 9.20 VAMTOP	HAL	3,001.75	3,002.05	2747.55	0.30	4.980	2.962	2.800
15.6		Durasleeve(R) Sliding Side-Door(R) Circulating and Production	HAL	3,002.05	3,003.27	2747.84	1.22	4.550	2.813	2.800
15.7		Reducing Adapter,3 1/2-9.20 VAMTOP Box x 4 1/2- 12.60 TSH BLUE	HAL	3,003.27	3,003.56	2749.02	0.28	4.544	2.940	2.800
		Pup Jt,4 1/2-12.60 TS-BLUE	TENARIS	3,003.56	3,006.51	2749.29	2.95	4.500	3.894	3.833
		TUBING,4 1/2-12.60 TS-BLUE	TENARIS	3,006.51	3,029.64	2752.15	23.13	4.500	3.894	3.833
		BL NIP,BN,240.0,13CR,4 1/2-12.60,,BOT 5.030 3.848 QTY 3	HAL	3,029.64	3,047.66	2774.50	18.02	5.030	3.848	3.833
		TUBING,4 1/2-12.60 TS-BLUE	TENARIS	3,047.66	3,107.06	2791.92	59.40	4.500	3.894	3.833
	ENI-LC-22-3.88-SA-01	Pup Jt,4 1/2-12.60 TS-BLUE	TENARIS	3,107.06	3,110.02	2849.34	2.95	4.500	3.894	3.833
13.1		Combination Adapter,4 1/2-12.60 TSHBLUE Box x 4 1/2-15.10 VAM-FJL	HAL	3,110.02	3,110.34	2852.20	0.33	5.765	3.868	3.833
13.2		Versa Latch Seal Unit Locator Assembly,3.88 inch Seal Bore ID-Min,4	HAL	3,110.34	3,111.32	2852.51	0.98	4.545	2.940	2.900
13.3		RTR Premium Seal Unit,3.88 in. Seal Bore ID-Min,13% Chrome Matl,	HAL	3,111.32	3,111.80	2853.45	0.49	3.864	2.940	2.900
13.3		RTR Premium Seal Unit,3.88 in. Seal Bore ID-Min,13% Chrome Matl,	HAL	3,111.80	3,112.29	2853.92	0.49	3.864	2.940	2.900
13.4		SELF-ALIGNING MULESHOE GUIDE, 3.880, 3 1/2-9.20 VAMTOP, BOX	HAL	3,112.29	3,113.20	2854.39	0.91	3.864	2.940	2.900
			Top of A4 Perf (MDRTm)	3032.00				Bot of A4 Perf (MDRTm)		3040.00
		7" Lower Completion Packer #1								
14.1	ENI-LC-22-7 VCH-01	Versa-Trieve(R) Retrievable Sand Control Packer VCH TYPE 7 in. 26-	HAL	3,110.43	3,112.66	2852.59	2.24	6.015	3.880	3.870
14.2		Bottom Sub for Versa-Trieve(R) Packer,VCH TYPE,5 13/32-8 STUB AC	HAL	3,112.66	3,113.12	2854.76	0.45	5.820	3.880	3.870
		Pup Jt,4 1/2-12.60 TS-BLUE	HAL	3,113.12	3,116.06	2855.19	2.95	4.500	3.894	3.833
15.5		Reducing Adapter,4 1/2-12.60 TSH BLUE Box x 3 1/2- 9.20 VAMTOP	HAL	3,116.06	3,116.36	2858.04	0.30	4.980	2.962	2.800
15.6		Durasleeve(R) Sliding Side-Door(R) Circulating and Production	HAL	3,116.36	3,117.58	2858.33	1.22	4.550	2.813	2.800
15.7		Reducing Adapter,3 1/2-9.20 VAMTOP Box x 4 1/2- 12.60 TSH BLUE	HAL	3,117.58	3,117.86	2859.51	0.28	4.544	2.940	2.800
		Pup Jt,4 1/2-12.60 TS-BLUE	TENARIS	3,117.86	3,120.81	2859.78	2.95	4.500	3.894	3.833
		TUBING,4 1/2-12.60 TS-BLUE	TENARIS	3,120.81	3,123.00	2862.63	2.19	4.500	3.894	3.833
			Top of A5 Re-Perf (MDRTm)	3168.00				Bot of A5 Re-Perf (MDRTm)		3186.00
			Top of A5 Perf (MDRTm)	3168.00				Bot of A5Perf (MDRTm)		3190.00

PERFORATION DATA

FORMATION	INTERVAL DEPTH (mMDRT)	GUN SIZE	SPF	CHARGES
A2U	2395.5 - 2406.5	7	12	PJO 4505
A2L	2416.5 - 2426.5	7	12	PJO 4505
A3	2830.0 - 2836.0	7	12	PJO 4505
	2840.0 - 2854.0	7	12	PJO 4505
A3.5	2900.0 - 2906.0	7	12	PJO 4505
	2911.0 - 2918.0	7	12	PJO 4505
A4	3032.0 - 3040.0	4 1/2	5	PJ 4505
A5	3168.0 - 3190.0	4 1/2	5	PJ 4505
A5 (RE-PERF)	3168.0 - 3186.0	2 1/2	6	PJO 2506

ADDITIONAL INFO

DESCRIPTION	QTY	MAT'L	MFG
TRSV SPECIAL CLAMPS (AS-7000-3863-12)	2ea	CARBON STEEL	COMPLETION PRODUCTS
7" X-CPLG CLAMPS (AS-7000-1-4269)	182ea	CARBON STEEL	COMPLETION PRODUCTS
TRSV C/LINE - 1/4" OD X 0.040" WT A825 WELDED & DRAWN SN: 35901-0-1	135.49m	PVDF / A825	TUBE-TEC
PDHG TEC/LINE - 1/4" OD X 0.035" WT 16 AWG SOLID TIN-COATED COPPER CONDUCTOR (FEP INSULATION / POLYOLEFIN) 11MM ROUND OD (YELLOW) SN: 35901-1	2109.18m	PVDF / A825	TUBTEC

VOLUME DATA

DESCRIPTION	(ml)	(bbls)	(m3)
CONTROL LINE RETURNS	106	n/a	0.000106
ANNULUS VOLUME TO PACKER	n/a	754.04	119.8

Figure 1.6: As Built Completion Schematic 1b

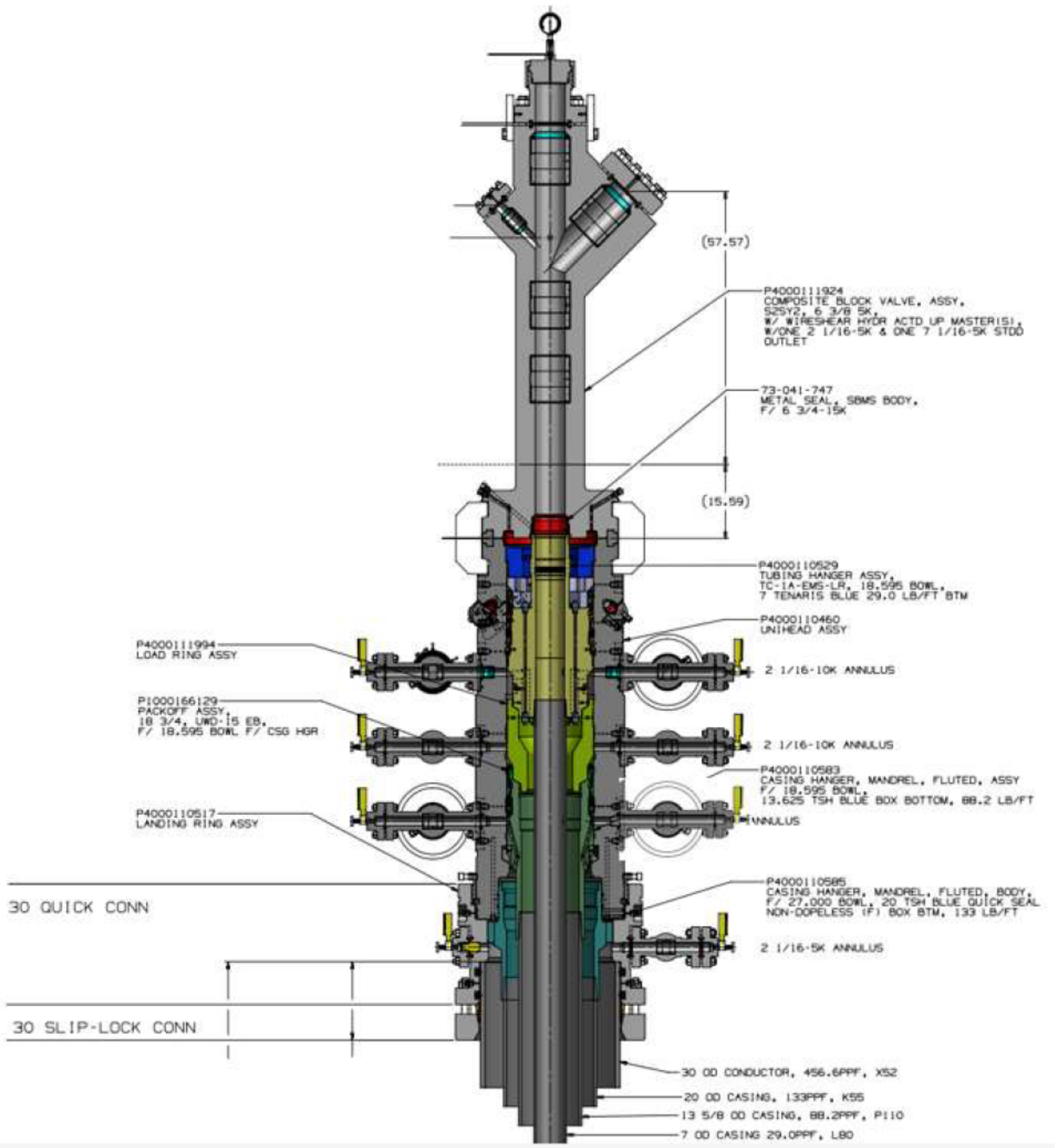


Figure 1.7: Wellhead and Production Tree General Arrangement

1.4.6 Current Well Integrity Status

During the construction of Blacktip P3, all well construction pressure tests were achieved. The two reservoir and completion barriers are still intact and all pre-production well acceptance criteria were achieved. It was only at the conclusion of the completion installation and acceptance testing on 13th February 2023, that the sustained casing pressure on the 20" x 13-5/8" casing annulus was noted.

The source of the 20" x 13-5/8" casing annulus pressure is thought to have occurred due to cement degradation of the 13-5/8" lead casing slurry, 1.43 sg (12.00 ppg). This allowed A1 gas to percolate to surface through a micro annulus in the cement.

A sample of the gas in the annulus gas confirmed a close match to the Mount Goodwin A1 gas. Following the confirmation of the gas composition, a leak detection log, in combination with a series of surface bleed offs, was carried out using the VIVID SEAL acoustic logging tool string. This log confirmed the deepest leak point to be at 1,300 m MDRT, with cross flow between reservoir layers and minor migration up through the cement sheath. The cement sheath barrier element is assessed as degraded, rather than failed. The logging results are explained in more detail, in section 2.3 Diagnostics.

The initial 20" x 13-5/8" casing annulus pressure investigation included two controlled bleed offs, followed by a corresponding pressure build up (PBU). The first of which was conducted on the 25th February 2023. With the well shut in to eliminate any thermal effects from the produced gas, the 20" x 13-5/8" casing annulus pressure, stabilised at 640 psi. This was bled down to 90 psi in 6 minutes and then allowed to build up again over a period of 12 hours. The pressure increased up to 660 psi over period of 3 hours and stabilised at 680 psi after 12 hours. See Figure 1.8 and Figure 1.9.

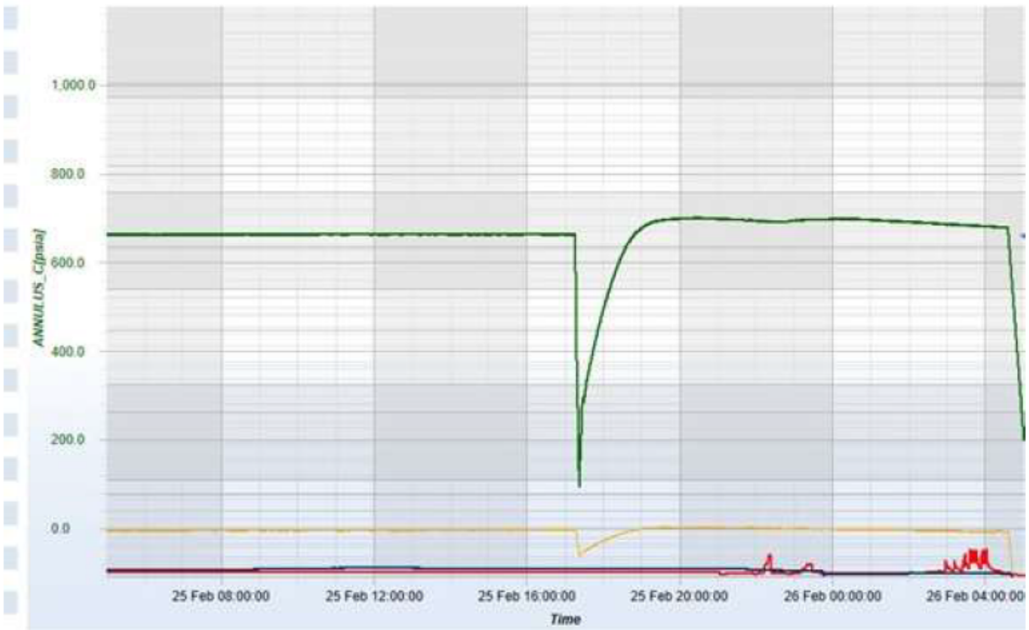


Figure 1.8: 20" x 13-5/8" Casing Annulus Pressure PBU 24 hrs

The relatively slow build-up of pressure is indicative of a casing micro annulus, allowing small volumes of gas to migrate through the cement and up to a point where the over balance prevents further migration.

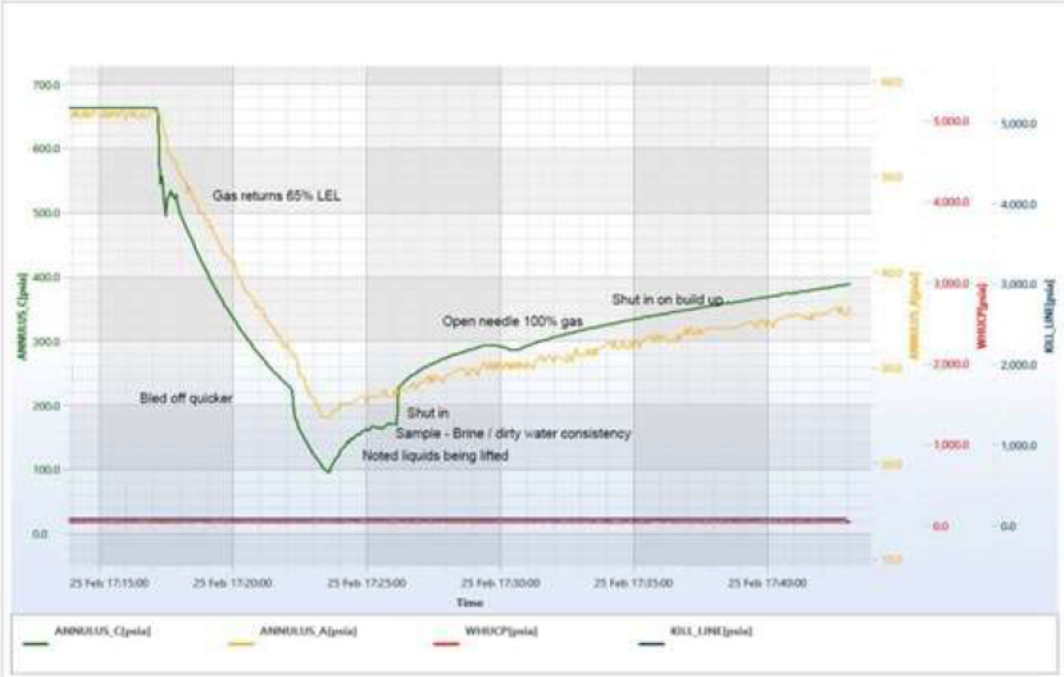


Figure 1.9: 20" x 13-5/8" Casing Annulus Pressure PBU initial 60 min

A second bleed off and pressure build up was conducted on the 4th April 2023. The pressure was bled down through a needle valve from 680 psi until liquid was noted in the returns. The lowest pressure attained was 470 psi after 3 minutes. The pressure built back up to 590 psi in 60 minutes and continued to increase over the following 3 hours to stabilise again at 680 psi.

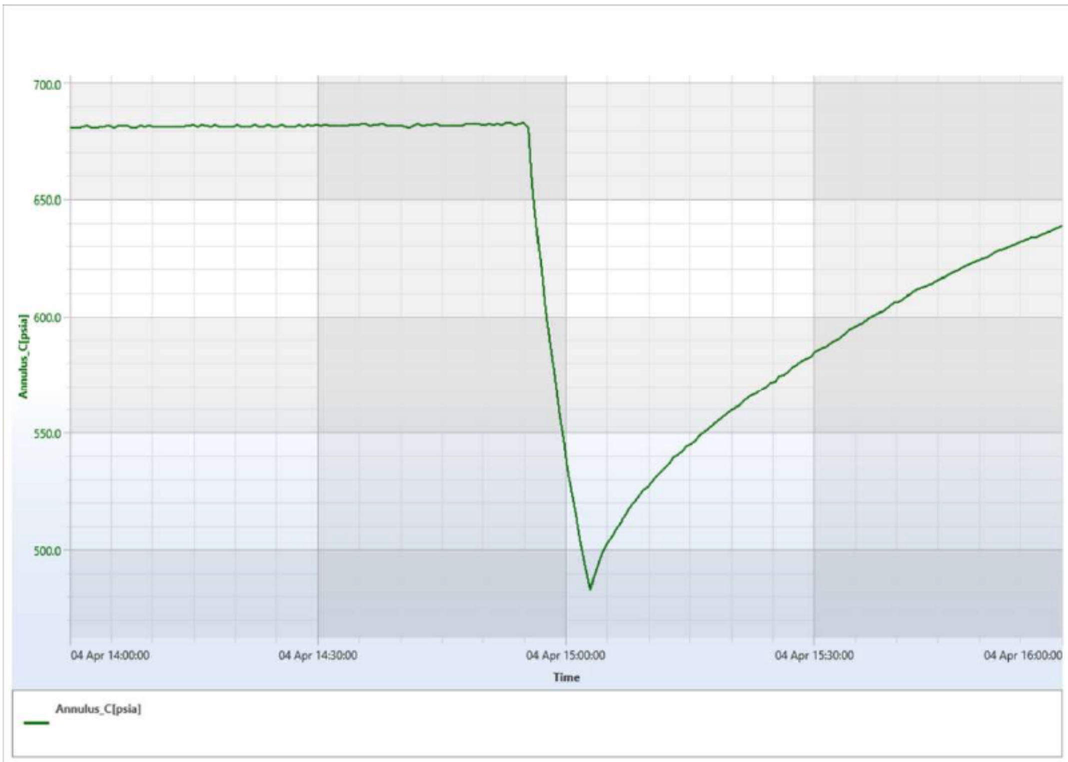


Figure 1.10: 2nd 20" x 13-5/8" Casing Annulus Pressure PBU initial 60 min

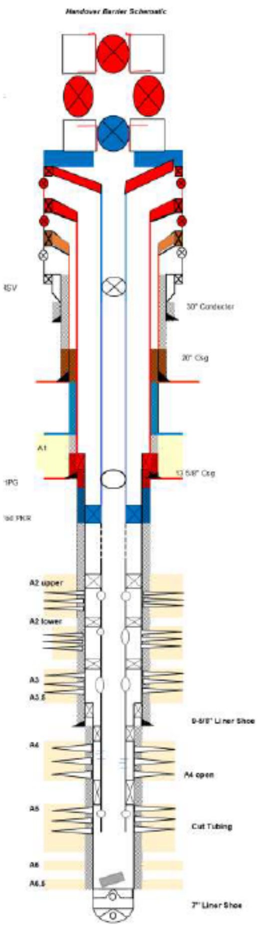
Below is a table detailing the 20 x 13-5/8" casing annulus pressure history, in relation to the well operations during construction, flow testing and during the well diagnostic activities.

Table 1.2: Activity and Annulus Pressure History

	Event	Date	20" x 13-5/8" Annulus Pressure
1	13-5/8" Casing Cementation, Pressure test to 3,650 psi with 1.2 sg mud.	6 Jan 2023	Zero
2	9-5/8" Liner cementation and pressure test to 2,900 psi with 1.15 sg mud	17 Jan 2023	Zero
3	7" Liner cementation and pressure test to 3,200 psi with 1.19 sg mud	25 Jan 2023	Zero
4	Lower completion Pkr#1 & well 3,650psi with 1.1 sg fluid	1 Feb 2023	Zero
5	Lower completion Pkr#2 & well 3,650psi with 1.1 sg fluid	5 Feb 2023	Zero
6	Lower completion Pkr#3 & well 3,650 psi with 1.1 sg fluid	5 Feb 2023	Zero
7	Pressure noted during wellhead pressure recording	13 Feb 2023	450 psi
8	15th Feb – LC Pkr#5 & well 3,650 psi with 1.1 sg fluid / 5 min	15 Feb 2023	450 psi
9	19th Feb – below prod Pkr 3,650 psi with 1.1 sg fluid / 15 min	19 Feb 2023	450 psi
10	20th Feb – Above prod Pkr & well 2,500 psi with 1.1 sg fluid / 15 min	20 Feb 2023	450 psi
Pressure gauge fault suspected, gauge replaced, and 220 psi pressure increase noted			
11	25th Feb – Bleed off pressure & monitor build up	25 Feb 2025	660 psi
12	20" x 13-5/8" casing annulus gas sample	Mar 2023	660 psi
13	Vivid leak detection logging	14 May 2023	663 psi before bleed offs
14	BT-P3 initial flow period, 20" x 13-5/8" casing annulus thermal expansion	29 May 2023	780 psi, bled down to 660 psi.
15	ScanWell flow survey and liquid level survey	5 Jun 2023	643 psi
16	[redacted]	[redacted]	[redacted]

1.4.7 Well Barrier Diagrams

The full well barrier diagram is detailed below in Figure 1.11. The well conforms to Eni standards, with two (2) barriers for a gas production well. The primary barrier envelope, including the production packer, tubing and TRSV, are all intact and have been verified on installation and during production testing of the well. The secondary barrier envelope, including the production casings, wellhead, casing hangers and tubing hanger, were confirmed on installation and prior to production testing.



Barrier Elements	Barrier Acceptance Criteria	Verification	Monitoring / Frequency
Primary Barrier Envelope - A1			
In-situ formation (A1 Seal)	PP/FG / WBS FG at Fossil head seal >1.4sg	20" FIT to EMW: 1.4 sg on 26/12/2022 13-5/8" FIT to EMW: 1.5 sg on 11/01/2023	During well construction
13-5/8" cemented casing	Pressure test of casing, Minimum 250m for annular barrier (unlogged)	Operative Parameters TOC calculated at 590m Plug bumped with estimated volume	Gauge monitoring available (remote monitoring scheduleded)
Secondary Barrier Envelope - A1			
In-situ formation (20" shoe)	Verified by formation integrity test (EMW> 1.34sg)	FIT to EMW: 1.4 sg on 26/12/2022	During well construction
20" Casing	Pressure test	Pressure tested with 1.03 sg SW/PHG/Polymer 2000 psi / 15 mins 25/12/23	During well construction
20" Csg cement	Minimum 250m annular barrier (unlogged)	Operative Parameters Tagged cement in shoe / Displacement volume	During well construction, Gauge monitoring available
13-5/8" cemented casing	Pressure test of casing Minimum 250m for annular barrier (unlogged)	Pressure tested with 1.2 sg WBM 3650 psi / 15 mins (green cement test) 06/01/23	Gauge monitoring available (remote monitoring scheduled)
Wellhead / 20" Fluted hanger	Pressure test	Pressure tested with 1.03 sg SW/PHG/Polymer 2000 psi / 15 mins 25/12/22	Gauge monitoring available
13-5/8" Seal Assembly / Wellhead	Pressure test	Pressure tested 10,000 psi / 15 mins 07/01/23	During well construction

★ Barrier degraded but not failed - inferred degradation due to observed casing pressure during well construction

Barrier Elements	Barrier Acceptance Criteria	Verification	Monitoring / Frequency
Primary Barrier Envelope - A2 - A6.5			
9-5/8" Production Packer	Pressure test	Pressure tested with 1.1 sg NaCl Brine 300 psi / 5 mins, 2500 psi / 5 mins 20/2/23	Annulus pressure monitoring above tested production packer via DHPG (remote monitoring)
9-5/8" Cemented Liner	Pressure test of Liner, cement logged >30m of good cement in annulus	Pressure tested with 1.1 sg NaCl Brine 300 psi / 5 mins, 3650 psi / 5 mins 15/02/23 BC-CBL 29/01/23	Annulus pressure monitoring above tested production packer via DHPG (remote monitoring)
7" Completion String	Pressure test	Pressure tested with 0.78 sg base oil 300 psi / 5 mins, 3650 psi / 5 mins 19/02/23	Downhole pressure gauge monitoring (remote monitoring)
Wellhead (WH/XT connector)	Pressure test	Pressure tested 300 psi / 5 mins, 5000 psi / 15 mins 22/02/23	During well construction
Secondary Barrier Envelope - A2 - A6.5			
9-5/8" Liner Top Packer, Liner Cement and Liner	Pressure test, Cement logged as >30m good cement in annulus	Pressure tested with 1.1 sg NaCl Brine 300 psi / 5 mins, 3650 psi / 15 mins 15/02/23 BC-CBL 29/01/23	Annulus pressure monitoring above tested production packer via DHPG (remote monitoring)
In-situ formation (13-5/8" shoe)	Verified by formation integrity test (EMW> 1.21sg)	FIT to EMW: 1.5 sg on 11/01/2023	During well construction
13-5/8" Cemented Casing to 2240m MD	Pressure test	Pressure tested with 1.2 sg WBM 3650 psi / 15 mins (green cement test) 06/01/23	Gauge monitoring available (remote monitoring scheduled)
13-5/8" Seal Assembly / Wellhead	Pressure test	Pressure tested 10,000 psi / 15 mins 07/01/23	During well construction
Wellhead (annulus valve)	Pressure test	Pressure tested with 1.1 sg NaCl brine 300 psi / 5 mins, 2500 psi / 15 mins 19/02/23	Gauge monitoring avaliable (remote monitoring)
Tubing Hanger (body seals)	Pressure test	Pressure tested 300 psi / 5 mins, 5000 psi / 15 mins 19/02/23	During well construction
Wellhead (WH/XT connector)	Pressure test	Pressure tested 300 psi / 5 mins, 5000 psi / 15 mins 22/02/23	During well construction
Tubing Hanger (SBMS seal)	Pressure test	Pressure tested 300 psi / 5 mins, 5000 psi / 15 mins 19/02/23	During well construction
X-mas Tree	Pressure test	Pressure tested 300 psi / 5mins, 3,650psi/5mins on 15/05/2023	During well construction

13 5/8" TTOC updated in Feb 2024 following a review of the MAWOP. Theoretical top of cement now 644m MD RT

Date: 24/05/2023

Figure 1.11: Primary Reservoir Barrier Diagram

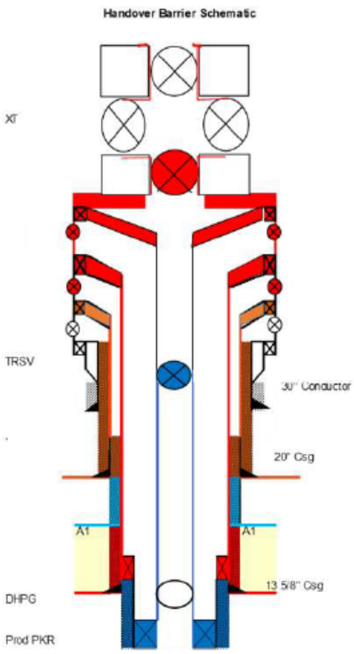
The Mount Goodwin sands sit outside the primary barrier envelope for the P3 main producing well & reservoir. The primary barrier for the Mount Goodwin A1 sands is the upper section of the 13-5/8” casing cement between 1,050 m MDRT and 20” casing shoe depth of 950 m MDRT.

The secondary barrier envelope for the Mount Goodwin A1 sands includes the 20” casing shoe, with an estimated strength of 1.60sg, the 20” casing, 13-5/8” casing, and the wellhead. This secondary barrier envelope is only partially shared with the secondary barrier envelope of the primary reservoir, specifically the 13-5/8” casing and 13-5/8” casing hanger. The degraded nature of the Mount Goodwin primary barrier results in sustained pressure in the secondary barrier envelope. The ability for hydrocarbon flow is minimal, but pressure transference is constant and stable.

The key elements of determining the risk profile for the P3 well are;

1. The ability of the Mount Goodwin secondary barrier elements to withstand the sustained casing pressure. The elements exposed are;
    a. Casing hanger seals.
    b. 20″ casing in burst.
    c. 13-5/8″ casing in collapse.
    d. 20″ casing shoe formation.

2. The interaction of the shared secondary barrier elements and the sustained casing pressure in the 20″ x 13-5/8″ casing annulus, has a material effect on the P3 reservoir secondary barrier mechanical performance. (Covered in Section 2 for calculated pressure limitations and risk assessed outcomes in the event of a failure in the primary or secondary barrier envelopes).



Barrier Elements	Barrier Acceptance Criteria	Verification	Monitoring / Frequency
Primary Barrier Envelope - A1			
In-situ formation (A1 Seal)	PP/FG / WBS FG at Fossil head seal >1.4sg	20" FIT to EMW 1.4 sg on 26/12/2022 13-5/8" FIT to EMW 1.5 sg on 11/01/2023	During well construction
13-5/8" Csg cement	Minimum 250m for annular barrier (unlogged)	Operative Parameters TOC calculated at 590m Plug bumped with estimated volume	Gauge monitoring available (remote monitoring) ★
Secondary Barrier Envelope - A1			
In-situ formation (20" shoe)	Verified byformation integrity test (EMW> 1.34sg)	FIT to EMW 1.4 sg on 26/12/2022	During well construction
20" Casing	Pressure test	Pressure tested with 1.03 sg SWPHG/Polymer 2000 psi / 15 mins 25/12/23	During well construction
20" Csg cement	TOC at seabed	Operative Parameters Tagged cement in shoe / Displacement volume	During well construction. Gauge monitoring available (remote monitoring) ★
13-5/8" Csg cement	TOC >150m above 20" casing shoe at 949.4m MDRT	Operative Parameters TOC calculated at 590m Plug bumped with estimated volume	Gauge monitoring available (remote monitoring)
13-5/8" Csg	Pressure test	Pressure tested with 1.2 sg WBM 3650 psi / 15 mins (green cement test) 06/01/23	Gauge monitoring available (remote monitoring) ★
Wellhead / 20" Fluted hanger	Pressure test	Pressure tested with 1.03 sg SWPHG/Polymer 2000 psi / 15 mins 25/12/22	Gauge monitoring available
13-5/8" Seal Assembly / Wellhead	Pressure test	Pressure tested 10,000 psi / 15 mins 07/01/23	During well construction

★ Barrier compromised - inferred degradation due to observed casing pressure during well construction

20″ Cement – Lead = 12.0ppg / 1.43sg Slurry. TTOC – 143m - 240 MD (56m below seabed, but >560m Minimum requirement

- Tail = 15.8ppg / 1.89sg slurry. TTOC – 849m MD (100m above shoe at 949m MD)

13 5/8" TTOC updated in Feb 2024 following a review of the MAWOP. Theoretical top of cement now 644m MD RT

Figure 1.12: Mount Goodwin A1 Sands Barrier Diagram

2. ANNULAR CASING MANAGEMENT PROCESS

2.1 Management System and Principles

Eni manages well construction and production activities using a guideline known as the MSG (Management System Guidelines) Operations. MSG Operations aims to provide guidance about the operating methods to be followed in the various phases of well integrity and delivery sub-processes, from well design, well completion, commissioning, and decommissioning. To integrate the MSG Operations and its Annex B (Well Integrity & Delivery) requirements with the local and regulatory requirements, Eni Australia has developed a specific process called the Well Process Manual (WPM).

Managing a well with sustained annulus pressure through the well life cycle, will follow the same guiding principles, policies, and responsibilities of the Well Process Manual (WPM).

2.1.1 Management Principles

The well operations process is potentially hazardous and throughout all aspects of the well operations lifecycle, Eni has defined standing principles that must be carried out to ensure all risks are maintained As Low As Reasonably Practicable (ALARP). Eni Australia is following thirteen (13) standing principles as listed in Table 2.1.

Table 2.1: Well Operation Standing Principles

No.	Standing Principles
1.	Perform all work in a documented workflow system.
2.	Ensure HSE is a key value in all well operations.
3.	Comply with Eni corporate technical and HSE requirements, relevant legislation and regulatory advice.
4.	Organise operations structures to clearly define responsibilities, roles and reporting.
5.	Ensure all Well Operation employees and contractors are competent, have the required training and are properly inducted.
6.	Integrate contractor and support services in managing operations and HSE.
7.	Manage risk by identifying hazards, assessing the risk and ensuring controls are in place to reduce risk to ALARP.
8.	Safeguard the occupational health of employees through systems and processes and encourage employees to participate.
9.	Provide procedures for the entire operations process which ensure safety under both normal and unexpected conditions.
10.	Provide a procedure for managing change.
11.	Audit and measure HSE, operational performance and competencies.
12.	Provide a process to improve systems through analysis and feedback.
13.	Support emergency response structures and procedures for handling emergencies (including rescuing, stabilising and evacuating personnel).

2.1.2 Well Integrity Policy

As per the Eni Well Integrity Management Procedure (STAP-P-1-MG-26526), well integrity is defined as the application of technical, operational and organisational solutions to reduce the risk of uncontrolled release of formation fluids to atmosphere or subsurface layers, throughout the life cycle of a well. It applies to exploration wells, production wells, injection wells, shut-in wells and temporarily abandoned wells. This integrity cycle is illustrated in Figure 2.1.

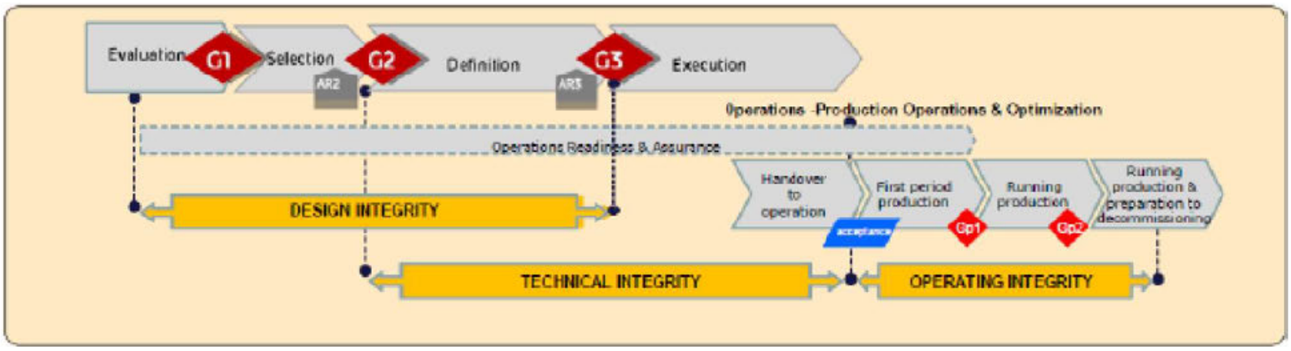


Figure 2.1: Asset Integrity Cycle

2.1.3 Well Integrity Management System

Eni Well Integrity Management Procedure (STAP-P-1-MG-26526), details the management of well integrity during the life cycle of a well. It provides guidance in the following areas;

- Roles and Responsibilities for Well Integrity Management.
- Handover Process.
- Well Integrity Management during Production Operations.
- Well integrity in well abandoning.
- Annulus pressure monitoring frequency.
- Management of wells with sustained casing pressure.
- Well Maintenance Activities.
- Reporting & Data Collection.
- Well integrity tool (WIT).

The management of well integrity starts with well design, continues through well construction, and is constantly assessed during the production phase.

When a well exhibits sustained casing pressure (SCP), a management of well integrity shall be activated. The risks posed by such an anomaly shall be assessed and addressed. A Risk Assessment shall be carried out based on the requirements stated in the Eni's "HSE Risk Management and Reporting" and "Guideline to Assess Blowout Probability Study During Drilling and Completion Operations" (STAP P-1-M-26506), by both the P&M function and D&C function, according to the appropriate area of competence. P&M function manages well maintenance (refer to the Eni's "Well Maintenance Procedure", STAP-P-1-MG-26527).

2.1.4 Management of Wells with Sustained Casing Pressure

ENI Well Integrity Management Procedure STAP-P-1-MG-26526 - rev.04, defines Observed Casing Pressure and Sustained Casing Pressure as follows:

- Observed Casing Pressure (OCP) is defined as any pressure measurable at the wellhead, of a casing annulus higher than 10 bar (150psi).

- Sustained Casing Pressure (SCP) is defined as any OCP that rebuilds to at least the same pressure level when bled down; it shall not be caused solely by temperature fluctuations, and shall not be a pressure that has been imposed by the Operator.

Eni has established specific tasks to manage wells with Sustained Casing Pressure (SCP), in compliance with international regulations and standards relevant to safe operations of oil, gas and condensate fields.

The following tasks are assigned to, and shall be performed by, the P&M function and D&C function:

- Production & Maintenance function.
  - Well Maintenance
    - Pressure monitoring (SCP).
  - Verify if OCP is lower than MAWOP
  - Controlled bleed-down on "B", "C", etc. annuli (when possible).
  - Routine monitoring of any SCP.
  - Reporting and database keeping.
- Drilling and completion function.
  - Calculation of the Maximum Allowable Annulus Surface Pressure (MAASP).
  - Calculation of the Maximum Allowable Wellhead Operating Pressure (MAWOP).
  - Define the operating annuli pressures envelope (considering minimum pressure to avoid vacuum and maximum pressure to avoid reaching MAWOP within the actual required bleeding time), as per "Well Site Handover STAP-P-1-MG-26526 - rev.04, page 29 of 59, Procedure Between Drilling and Completion Function and Production Function" (STAP P-1-MG-26529).
  - Definition of possible causes of SCP;
  - Remedial actions in SCP wells:
    - Well intervention (if managed by D&C function).
    - Workover Operations (WO).
    - Well Abandonment;
  - Reporting and database keeping .

2.2 Responsibilities

2.2.1 Organisational Structure and Tasks

Roles and responsibilities and authorities of key personnel and position(s) responsible for the integrity of the well during its life cycle, are detailed in STAP-P-1-MG-26526.

2.2.2 Personnel Responsibilities

The responsibilities of the relevant managers are described as below.

- Business Unit Managing Director - The Subsidiary Manager is responsible for ensuring that the organisation and tools to support the well site handover process are properly developed and maintained.
- Operations Manager - The Operations Manager is the single point of contact accountable for ensuring that all the requirements of the Well Integrity Management Procedure and the referenced procedures and reporting requirements are complied with. In the case that current operating practices fail to meet such requirements, the Operations Manager is responsible for putting in place a remedial compliance plan. The Operations manager shall validate on a quarterly basis well integrity data and parameters contained in WIT software.
- Production & Maintenance Function (P&M) - The Manager of Production & Maintenance Function, directly reporting to the Operations Manager, responsible for all aspects aimed to guarantee the integrity of the wells, including gathering of annuli pressures, X-mas tree and SCSSV periodical tests. Responsible for the acceptance of wells transferred from the Well Operations Function, to enable a safe, smooth start-up leading to fully sustainable production operations. The Production and maintenance function shall ensure that appropriate processes and procedures are in place and implemented to perform the handover to the Well Operations Function. In case of loss of well integrity, Production and maintenance function shall involve drilling and completion function for analysis and possible remedial actions.
- Drilling and Completion function (D&C) - The Drilling and completions function is responsible to transfer to P&M function, throughout the handover process, all the well data and relevant information required for proper well handling and well integrity management. Upon identification of well integrity shortfall or notification by the P&M function of well integrity anomalies, the D&C function is responsible to identify specialist expertise and develop appropriate operating procedures to fully assess and resume well integrity as needed. Moreover, D&C function shall:
    - in cooperation with the P&M function prepare a well intervention schedule and budget aimed to restore well integrity.
    - in cooperation with P&M function verify that well integrity requirements meet local Authority regulations.
    - D&C function, duly activated by Production & Maintenance function, is responsible for undertaking remedial actions to restore well integrity.
    - guarantee the control and the periodical updating of relevant data required by the WIT software.

2.3 Diagnostics

Four diagnostic tests have been undertaken to identify the source of the gas, confirm the leak path, measure the leak rate, and measure the liquid level in the annulus.

2.3.1 Gas Sample Fingerprinting

The gas from the 20" x 13-5/8" casing annulus was sampled in March 2023 and sent to Core Lab for gas chromatography finger printing. These results were compared to the results from the varying reservoir levels in the Blacktip development. The very high Methane content of 99% (normalised for HCgas) is consistent with Mount Goodwin gas, with the Keyling/Treachery reservoirs having much lower Methane percentages of 90 to 96 percent.

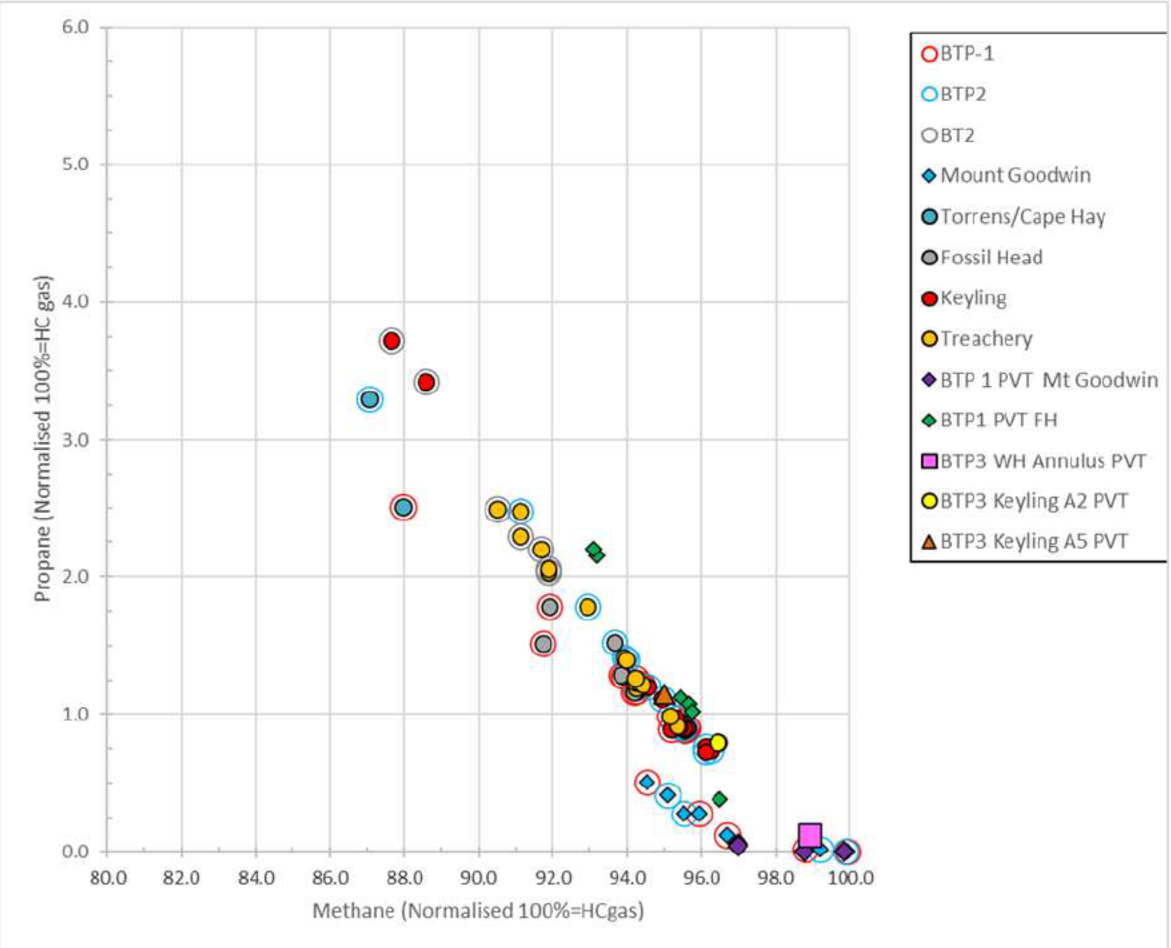


Figure 2.2: Gas Fingerprinting Plot

2.3.3 Archer VIVID Logging – Leak Detection

The VIVID Seal logging string is designed to detect the smallest of fluid movements downhole. High-speed sampling allows statistical parameter analysis over a broad frequency range, with greater resolution at low frequencies. The tool can measure cement sealing quality, gauge flows, even in the presence of cement micro-annuli and locate minimal flow levels through a cement barrier.

The tool was run in hole through the production tubing, with the well shut in. A baseline pass was completed with the annulus shut in with 680 psi at surface. The 2nd leak detection pass was completed with the annulus periodically bled down from 680 psi to 400 psi and allowed to build up. The pressure build-up rate was consistent throughout the diagnostic logging at 300 psi/hr.

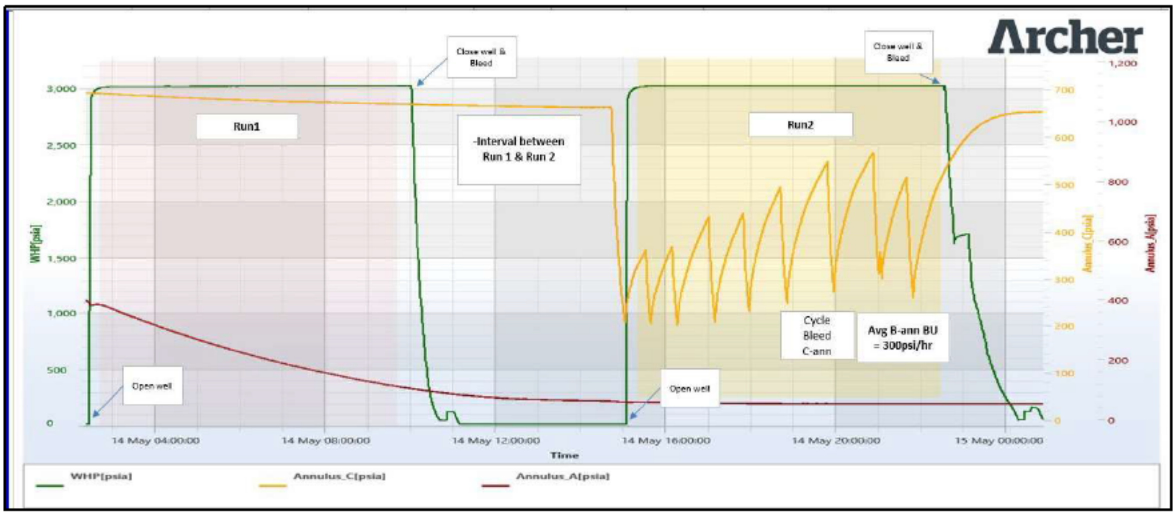


Figure 2.3: Surface Graph While VIVID Logging

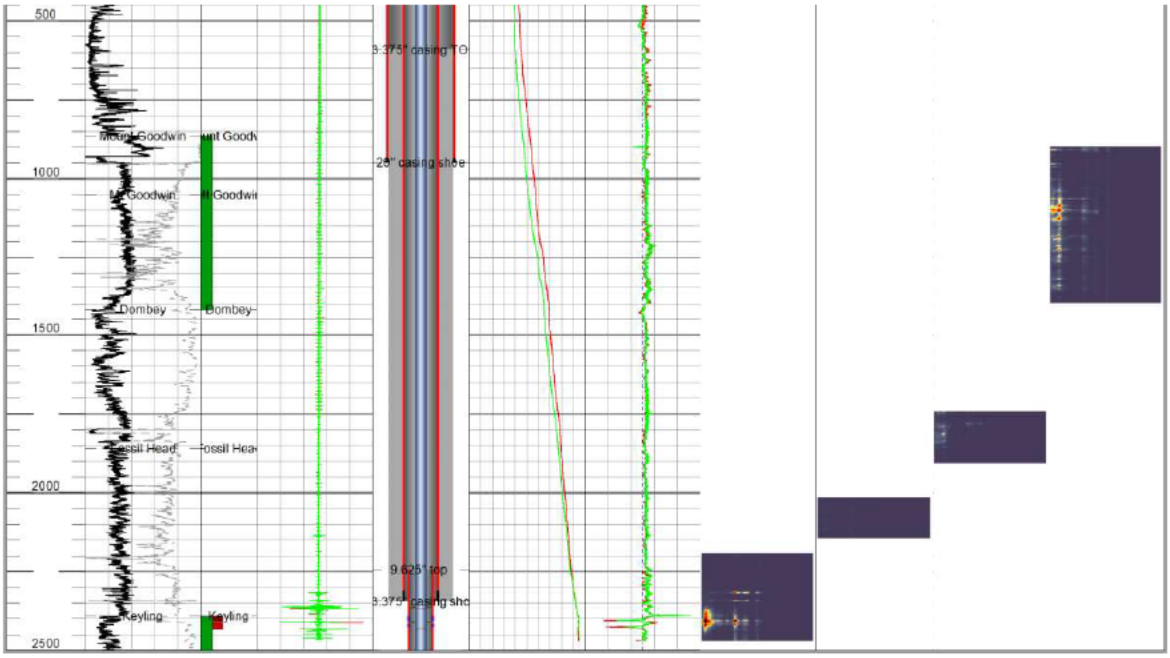


Figure 2.4: VIVID Full Log Results

The log confirmed the integrity of the cement above the primary Keyling A2 reservoir, with no acoustic anomalies recorded in the cement above the primary reservoir. The VIVID tool recorded notable acoustic events across the primary reservoir area, which is interpreted as cross flow between reservoir layers with the well shut in.

The log data shows an acoustic energy increase across formation units A1_1-A1_10 (interval 1,050 m-1,300 m) during both well conditions. The well was shut-in for 6 hours before the static survey was carried out, resulting in the changing 20" x 13-5/8" casing annulus pressure. The formation fluid can migrate between the rock layers during the shut-in period due to formation pressure differences, lateral flow, and presence of fracture/faults. The most prominent acoustic energy changes were observed within zones A1_1 - A1_5 (1,050 m-1,145 m), indicating the majority of the flow originates from this interval. The acoustic response appears to be intensified across this interval during the venting condition. Acoustic anomalies at the depths of 906 m, 951 m and 1,012 m are suggestive of a further annular gas migration path to surface. Acoustic events are also found across layers A1_6 and Tern formation (1,150 m-1,300 m) demonstrating the annular gas flow across these zones.

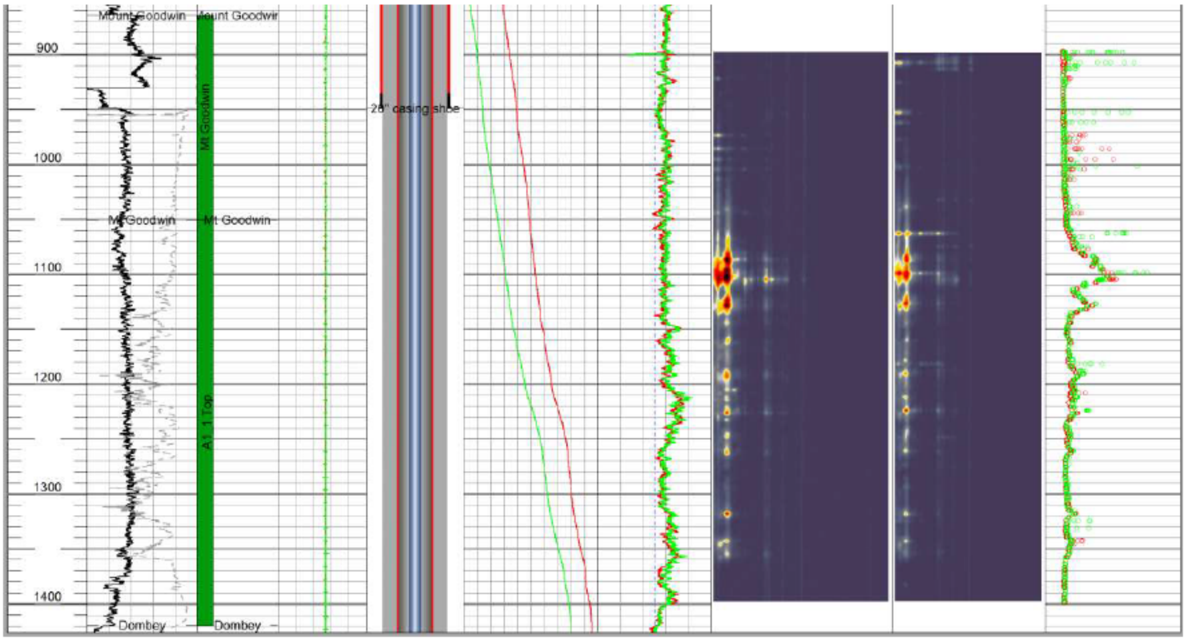


Figure 2.5: Mount Goodwin VIVID Log Results

The survey data shows a clear indication of annular gas flow across subgroup layers of Mt Goodwin formation within the interval 1,050 m-1,300 m. The gas flow and its annular migration from these zones to the surface, appear to be the main source of SCP on the 20" x 13-5/8" casing annulus.

The relatively slow build-up of pressure is indicative of a casing micro annulus allowing small volumes of gas to migrate through the cement up to a point where the overbalance prevents further migration.

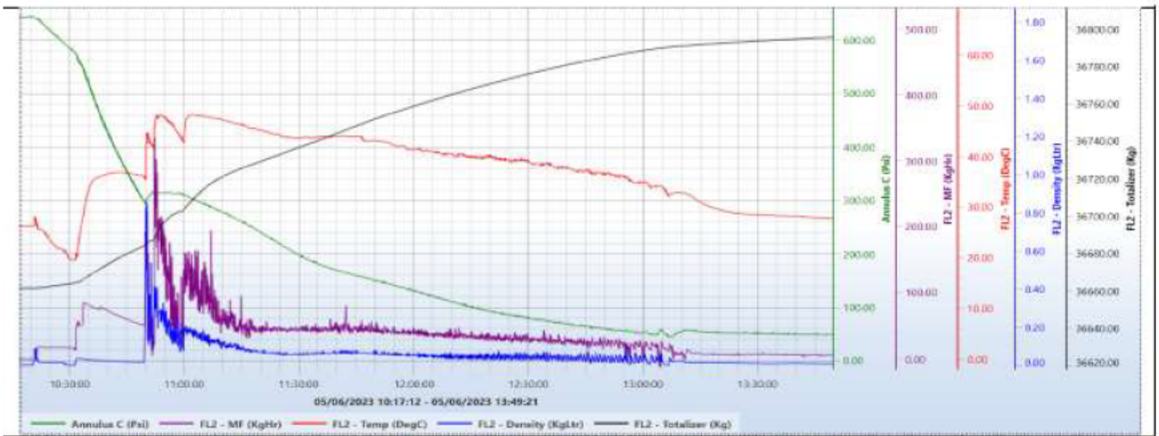
2.3.4 Leak rate and Annulus fluid level

A ScanWell annulus flow measurement tool was used to measure the gas leak rate, pressure build up and an acoustic metering survey carried out to determine the annulus fluid level.

Table 2.2: Well Operation Sequence

05.06.23	10:10	Record initial pressure
05.06.23	10:11	Acoustic measurements
05.06.23	10:19	Start bleed down
05.06.23	13:49	End bleed down
05.06.23	13:50	Start leak metering
05.06.23	14:50	End leak metering
05.06.23	14:53	Start pressure build-up
05.06.23	15:01	Acoustic measurements
05.06.23	15:23	End pressure build-up
06.06.23	08:33	Acoustic measurements

The ScanWell leak metering survey was attached to the 20" x 13-5/8" casing annulus while the P3 well was producing. The A-annulus (tubing x 13-5/8" casing) pressure was allowed to increase to approx. 2,100 psi via thermal expansion.



Date	Time	Annulus C (Psi)	FL2 - MF (KgHr)	FL2 - Temp (DegC)	FL2 - Density (KgLtr)	FL2 - Totalizer (Kg)	Comments
05.06.23	10:19	643.39	0	26.34	0	36661.49	Start
05.06.23	13:49	49.6	6.57	27.88	0.01	36795.77	Stop 03:29:55

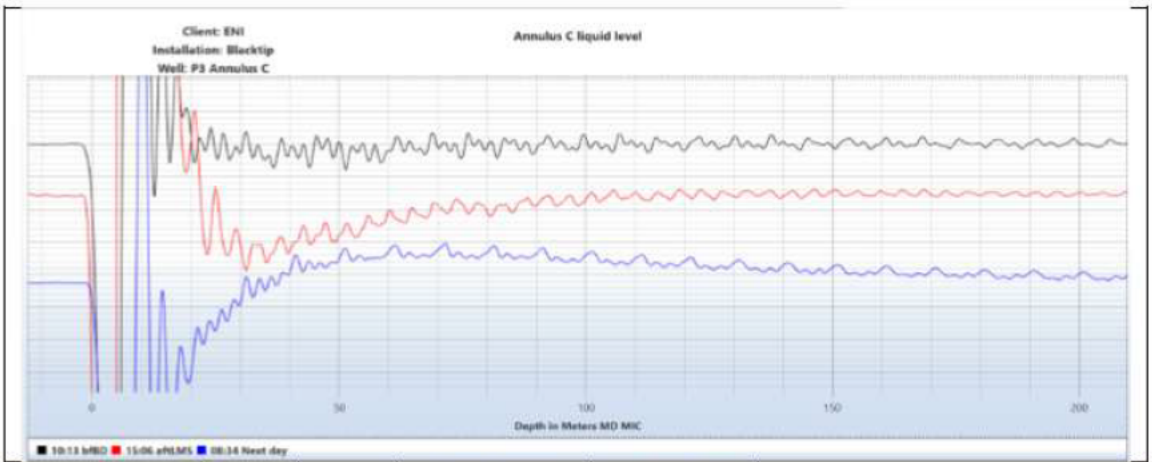
Figure 2.6: Initial Bleed Off Results

The initial gas cap was bled down from 643 psi to 296 psi before a mix of gas and liquid was noted at surface. In order to stabilise the flow rate, the pressure was reduced to 49 psi before commencing the leak rate measurement survey. The initial bleed off resulted in 134 kg of gas/fluid mix, predominantly gas.

	Date	Time	Ann-C (psi)	Temp (C°)	Density (kg/ltr)	Mass Flow (kg/hr)	Gas Leak Rate (scf/min)	Liquid Leak Rate (ltr/min)
Leak Rate Measurement	05.06.23	14:49	48.9	28.0	0.011	*6.35	4.36	N/A

Figure 2.7: Leak Flowrate Results

The leak measurement survey was conducted with the well in production and the 20" x 13-5/8" casing annulus open. The pressure, temperature and flowrate remained stable for the 1 hr measurement period. The measured flowrate was 6.35 kg/hr, which equates to 4.36 scf/min.



Date	Color	Time	Annulus Pressure (psi)	Liquid Level (m MD)	Comments
05.06.2023	Black	10:13	644	Shallow / 2.5m	Before bleed down
05.06.2023	Red	15:06	98	Shallow / 4m	After leak metering
06.06.2023	Blue	08:34	563	Shallow / 2.5m	Next day

Acoustic measurements comments:

- The acoustic trace indicates a shallow liquid level. Time between the reflections is equivalent to the depth in the table above.

Figure 2.8: Annulus Fluid Level

The fluid level was measured acoustically before the bleed down, after the leak monitoring survey, and 24 hours following the survey. The fluid level was found to be between 2.5 m and 4 m below the wellhead in all instances. This gives greater certainty that the leak is one way, with gas able to migrate up through the cement micro annulus, but fluid not being able to leak off through the cement to the formation.

2.3.5 20" x 13-5/8" annulus Pressure Build-Up During Production

The annulus pressures before, during and following the ScanWell survey are graphed below. The well was bought on production on 1st June, with the A-annulus pressure increasing from 60 psi to 2,150 psi through thermal expansion of the A-annulus fluid. During the initial flow period, the 20" x 13-5/8" casing annulus pressure increased to 725 psi through a combination of thermal effects and expansion of the inner 13-5/8" casing. The pressure was bled down to 350 psi, the pressure then increased and stabilised at 635 psi prior to commencing the ScanWell survey. Following the ScanWell survey, the 20" x 13-5/8" casing annulus was shut in and stabilised at a pressure of 575 psi. The pressure then remained stable for the following 5 days.

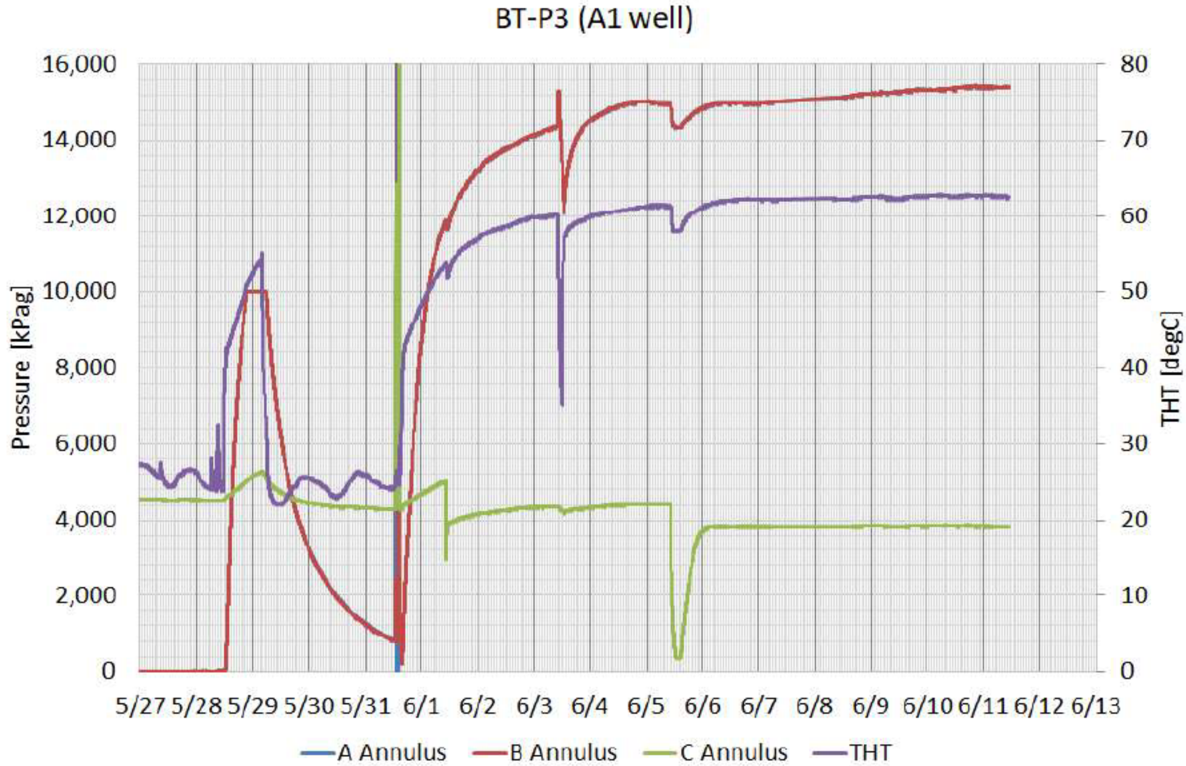


Figure 2.9: Annulus Pressures During and Following ScanWell Survey

2.3.6 Diagnostic Conclusions

The results from the 4-diagnostic tests confirm the pressure observed in the 20" x 13-5/8" casing annulus is due to gas migration from the Mount Goodwin formation. The relatively slow build-up of pressure and very low flow rate is indicative of a casing cement micro annulus, allowing small volumes of gas to migrate through the cement up to a point where the overbalance prevents further migration. When bled off the pressure drops off quickly with a minimal sustained flow rate of only 4.36 scf/min which is below the API 14A acceptable leak rate for a down hole TRSV with a safety factor of 3. The 20" x 13-5/8" casing annulus pressure stabilises at 575 psi when thermal expansion effects are eliminated. The fluid level in the annulus is stable at between 2.5 m and 4 m below the wellhead. The leak can be assumed with a high degree of confidence to be one way, with gas able to migrate up through the cement micro annulus but fluid unable to leak off to the formation below the shoe.

2.4 Documentation and Record Keeping

Eni have a specific software named Well Integrity Tool (WIT) that has been developed to support well integrity during all phases on the well lifecycle. The monitoring is performed locally and by HQ D&C function.

2.4.1 Well Integrity Tool (WIT)

WIT uses collected data to provide a comprehensive overview of the current integrity status by mapping the integrity status of the Company's worldwide wells.

This tool is available via the Internet at the URL wellintegrity.Eni.com, and Eni Intranet (via T/S portal). Any Eni employee (Drilling, Completion, Production a Maintenance Engineers, along with relevant Managers) can access the application, for the wells of his / her competence, providing he / she has an ENINET ID.

The tool based on a "traffic light" logic working just on the three main aspects of the well integrity: the Downhole Safety Valve status, the Wellhead and Christmas Tree status and the tubing-casing and casing-casing Annuli status.

By simply periodically updating the data about the tests and monitoring performed onto these 3 items, the tool provides the status of each one of the 3 and the whole condition of the well, given by the worst status of each single barrier element.

In this logic, "green" means that the status is ok and there are no issues (the barriers are effective, tested and maintained); "yellow" means that the status of the barriers is still ok (they are still effective), but there is an alert due to test date being expiring or any minor anomaly on annulus pressures or other particular reasons for alert; "red" means that there is an alarm due to one or more barrier(s) being lost or data completely missing.

WIT is composed by two different sections:

- WIT - Input Tool
- WIT - Dashboard Analysis 11

The Input Tool collects the necessary data for mapping the safety conditions of all wells. The Dashboard Analysis can be used for a qualitative analysis on wells integrity condition.

This dashboard analyses shows an Alarm Status according to the Eni procedures stated in "Well Integrity Management Procedure", STAP P-1-MG-26526 and in the "Well Maintenance Procedure", STAP-P-1-MG-26527.

Each single alarm has three levels, GREEN light: for wells where there are no integrity problems. YELLOW light: state of alert; for wells where there are some anomalies to be investigated or monitored. RED light: state of alarm; for wells where critical conditions require immediate action. The worst value (light) of single alarms determines the general status of the well.

2.5 MAASP & MAWOP

Due to the nature of the 20" x 13-5/8" annulus sustained casing pressure, the Maximum Allowable Annulus Surface Pressure and Maximum Allowable Wellhead Operating Pressure for Blacktip P3 do not conform exactly to the API 90.1 standards, primarily due to the one-way nature of the leak path in the cement sheath. Gas can migrate up through the micro annulus in the cement sheath, but fluid does not appear to leak off to the formation below the 20" casing shoe.

The MAWOP is calculated based on the best equivalent hydrostatic head inside the microannulus, the fracture pressure below the shoe, the hydrostatic pressure above the TTOC and the surface annulus pressure read.

The MAASP set at the minimum internal 13-5/8" casing collapse pressure of 2,415 psi.

The MAWOP pressure is calculated based on a 20" shoe formation strength of 1.6 sg, with the micro annulus assumed to be [redacted]

[redacted]

Figure 2.10: Steady State and MAWOP Pressures

[1] Based on the MDT data, the reservoir gas gradient in Mount Goodwin is 0.018-0.046psi/ft.

The likelihood of reaching or breaching the MAASP is negligible as the formation pressure in the Mouth Goodwin is 1,432 psi and during well start up, the thermal expansion effects have been limited to approximately 150 psi.

Table 2.3: MASSP & MAWOP Calculations

Case	Element	MAASP psi	MAWOP psi	Comments
Inner Casing Collapse	13-5/8"	3,772	3,018	20" x 13-5/8" casing annulus hydrostatic 208 psi greater than the A-annulus hydrostatic at the 20" shoe depth.
Inner Casing Collapse (A-Annulus evacuation case)	13-5/8"	2,415	1932	Assumption being the A-annulus fluid drops to below the 20" casing shoe depth due to a packer failure.
Outer Casing Burst	20"	3,060	2,448	
WH/XT Rating (B Annulus Elements)	13-5/8"-20"	5,000	4,000	S Seals on UH bottom prep top and bottom S Seal test at 1,200 psi/5 min.
Formation Strength	20" shoe		[redacted]	[redacted]

MAASP 20" x 13-5/8" Annulus	**2415**	**psi**	Assumption being the A-annulus fluid drops to below the 20" casing shoe depth due to a packer failure.
MAWOP 20" x 13-5/8" Annulus	[redacted]	**psi**	Limited by the 20" shoe Formation Strength

2.6 Well Operations Considerations

2.6.1 Monitoring Method and Frequency

All blacktip wells tubing heads, A-annulus, 20” x 13-5/8” casing annulus, and 30” x 20” casing annulus pressures, are continuously monitored via pressure sensors on the wellhead and annulus outlets. Data is continuously transmitted via the DCS to the Production Operator in the Central Control Room at the Yelcherr Gas Plant. Alarms are set for each annulus which will activate in the event of an increase outside normal limits.

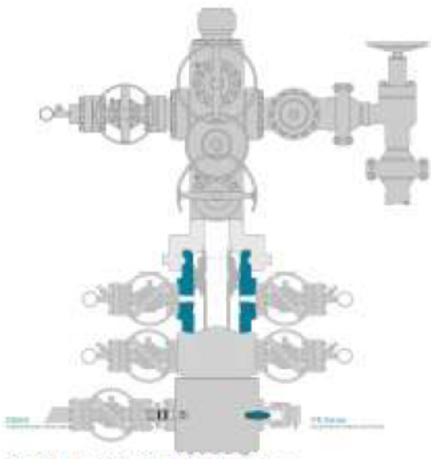
Table 2.4: Blacktip Annulus Alarm Levels (PSI)

Well	A annulus	B annulus	C annulus
P1	650	800	540
P2	650	800	540
P3	2,670	N/A	780

2.6.2 Additional monitoring considerations for Blacktip P-3

Continuous monitoring of the 20” x 13-5/8” casing annulus pressure would ordinarily require the inner annulus outlet valve to be left open. The outlet is exposed to dropped object risks which could result in a loss of containment. A pressure monitoring VR plug technology is available from Interwell, via their PTC subsidiary. The Master Surface Annulus Safety Valve (MSAS®), fail-safe close barrier valve solution, provides independent double barrier integrity at wellhead side outlets. The MSAS mitigates the risk of uncontrolled release of annular content from leaks or accidents, including dropped objects. The system will incorporate their VR Sense VR plug design.

The VR Sense system consists of the VR Sense plug, VR Sense flange and VR Sense connection box. The VR Sense plug is installed in the wellhead’s VR profile. The VR Sense plug is the primary barrier and functions as a blind plug with a sensor, which measures pressure and temperature in the annulus cavity.



Option 1. MSAS and VR Sense
Proposed wellhead setup with dual barriers on B-Annulus outlets to comply with dual barrier policy against any hydrocarbons

Figure 2.11: Interwell MSAS & VR Sense

The MSAS provides an additional independent barrier in the wellhead VR profile. The MSAS is hydraulically operated and connected to the ESD. Should an impact or collision take place, the API6FD/FB fire tested barrier valve locked in the tailor-designed spacer spool, will close and remain within the wellhead, thus securing the pressurised annular volume. The MSAS system can also be integrated in an API gate valve (MSAS-G) and has a smaller footprint as the valve actuator is installed within the gate valve bore.

2.6.3 Corrosion/Erosion Management Considerations

The 20" x 13-5/8" casing annulus fluid level has been measured to be between 3 m and 5 m below the wellhead level. During the wells production life, the annulus level will vary, dependant on the temperature and pressure in the annulus. This variation will introduce a corrosion risk that will be managed with periodic inspections.

Both internal and external corrosion measuring techniques are being assessed. The Baker MID (Magnetic Imaging Defectoscope) tool is being assessed for periodic internal logging of the 13-5/8" and 20" casing. The tool can evaluate quantitatively the casing metal loss of up to 3 casing strings and qualitatively for the 4th casing string. Similar logging technologies are also available and can be deployed to investigate the casing metal loss.

Through periodic logging, a timelapse metal loss measurement can be developed to ensure the barrier envelope design pressures can be updated and mitigations implemented of corrosion is measured.

Magnetic Imaging Defectoscope – S4

Tool specifications

- Operates in all normal well bore fluids
- Operates in deviated or horizontal wells with centralizers
- Logging in SRO mode on mono-conductor wireline
- Tool maximum OD – 1.65" (42mm)

Instrument length	Weight	Max pressure	Max temperature	Barriers
144" (3672mm) includes centralizers	14kg includes centralizers	15000 psi (100 MPa)	302°F (150°C)	4

Min ID	Max ID	1 pipe WT	2 pipes WT	3 pipes WT	4 barrier
2.5"	20"	Max 0.629"	Max 1.259"	Max 1.889"	Max 1.9"
Accuracy		5%	10%	15%	20%
Min length of "crack"		1/9 of perimeter	¼ of perimeter	⅓ of perimeter	½ of perimeter

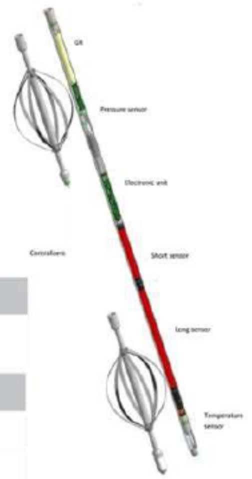


Figure 2.12: Baker MID Tool Specifications

2.6.4 Well Abandonment considerations.

Blacktip P3 will be abandoned when the field is decommissioned. The well will be plugged and abandoned in line with ENI abandonment policies, which are aligned with international standards of OGUK and NORSOK.

The isolation of the Mount Goodwin formation will require 2 x permanent barriers to be placed across the cap rock. The micro annulus in the cement behind the 13-5/8" casing will therefore require remediation to ensure a minimum of 60 m of sealing cement is placed across the cap rock.

Technologies currently available to remediate the micro annulus include section milling, perf wash and cement (PWC) and resin squeezes. Emerging and new technologies will also be assessed at the time of the abandonment planning.

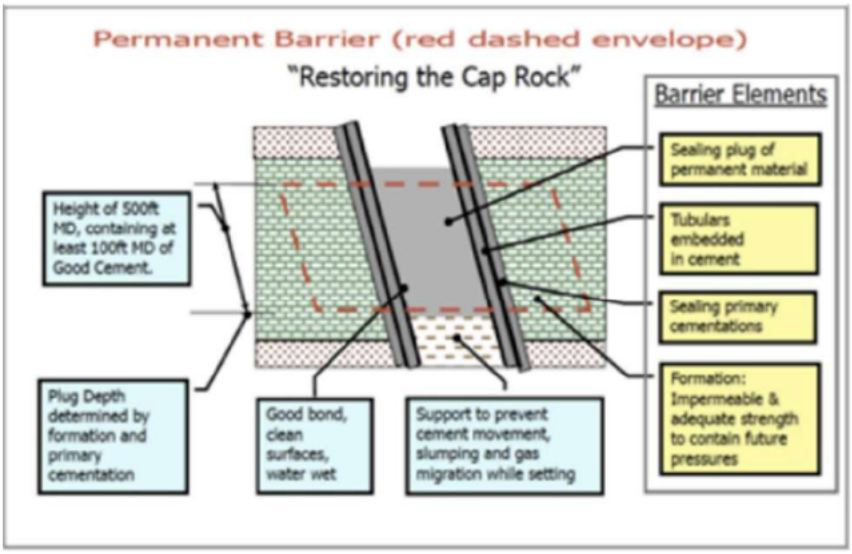


Figure 2.13: UKOG Restoring Cap Rock Diagram

3. RISK ASSESSMENT

ID #	Activity	Applicability	Hazard	Consequence	Risk			Existing Prevention or Mitigation Controls	Risk		
					Severity	Prob	Risk Rating		Severity	Prob	Risk Rating
No	Risk	Personnel, Environment, Damage Schedule	Risk description	Risk Impacts	Original risk			Prevention – prevent hazard event occurring & reduce the likelihood of event. Mitigation - reduces the consequence.	Mitigated risk		
20" x 13-5/8" annulus Pressure											
1	P3 Production with 20"x13 5/8" annulus micro annulus and sustained casing pressure	People H&S	Annulus pressure exceeds MAASP during unmanned production activities	1. Breakdown of formation at the 20" shoe leading to a loss of containment at seabed 2. P3 Production temporary Shut down	1	C	Low	**Preventative Measures** 1. TTOC inside 20"x13 5/8" annulus is 644m which is 305m inside 20" shoe. 2. ScanWell leak and fluid level surveys confirmed leak is one way with gas able to migrate up through the cement micro annulus but fluid unable to leak off to the formation. 3. Annulus pressure is continuously monitored in the Yelcherr gas plant control room. 4. 20"x13 5/8" annulus pressure alarms automatically trigger if MAWOP is exceeded (Note: the alarm is set at 780psi, while MAWOP is 1,159psi). 5. Mount Goodwin reservoir pressure is 1432psi which would require almost full evacuation to gas to breach the MAWOP pressure (Note: MAWOP is re-calculated based on the post-Drill PPFG chart provided by Eni HQ).	1	A	Low
		Environment			2	C	Low		2	A	Low
		Cost/ Business Loss			2	C	Medium	**Mitigating Controls** 1. Well services team mobilised to WHP within 24hrs to investigate and bleed down annulus pressure when the alarm limit of 780 psi was reached. 2. 20" shoe is set in the sealing cap rock limiting the possibility of breakdown and migration to shallow formations and seabed. 3. The leak rate is 4,55 scf/min , this is a 1/3rd of the allowable leak rate for a TRSSV as per API 14a	2	A	Low
		Corporate Image			2	C	Medium		2	A	Low
2	P3 Production with 20"x13 5/8" annulus micro annulus and sustained casing pressure	People H&S	Annulus pressure exceeds MAASP during unmanned production activities	1. 13 5/8" casing collapse 2. Damage to production tubing and loss of primary barrier envelope. 3. 20" casing exposed to THP gas to surface 4. Loss of containment.	1	B	Low	**Preventative Measures** 1. Annulus pressure is continuously monitored in the Yelcherr gas plant control room. 2. 20"x13 5/8" annulus pressure alarms automatically trigger if MAWOP is exceeded. (Note: the alarm is set at 780psi, while MAWOP is 1,159psi). 3. Collapse pressure is 1500 psi above the Mount Goodwin gas to surface pressure which is the maximum feasible surface pressure (Worst Case 13 5/8" casing collapse pressure is based on a simultaneous production packer failure and the highest gas pressure in the 20"x13 5/8" annulus). 4. Full evacuation to gas prevented as TTOC inside 20"x13 5/8" annulus is 644m which is 305m inside 20" shoe. ScanWell leak and fluid level surveys confirmed leak is one way with gas able to migrate up through the cement micro annulus but fluid unable to leak off to the formation.	1	A	Low
		Environment			3	B	Medium		3	A	Low
		Cost/ Business Loss			3	C	Medium High	**Mitigating Controls** 1. Well services team is mobilised to WHP within 24hrs to investigate and bleed down annulus pressure when the alarm limit of 780 psi is reached 2. 20" Casing and wellhead rated to a minimum pressure of 3060 psi (20" casing burst) which is above the maximum expected pressure at surface. For 20" casing exposed to this pressure, the tubing string shall leak in combination with the 13 5/8" casing collapse.	3	A	Low
		Corporate Image			3	C	Medium High		3	A	Low
3	P3 Production with 20"x13 5/8" annulus micro annulus and sustained casing pressure	People H&S	20"x13 5/8" annulus casing corrosion leading to failure of 20" or 13 5/8" casing.	1. 20" casing burst immediately below the wellhead. 2. 13 5/8" casing collapse 3. 20" casing exposed to A-annulus pressure 4. Loss of secondary barrier envelope.	1	B	Low	**Preventative Measures** 1. Annulus pressure is continuously monitored in the Yelcherr gas plant control room. 2. 20"x13 5/8" annulus pressure alarms automatically trigger if a pressure lower than the MAWOP is exceeded. 3. Casing corrosion monitoring to be in place on an opportunistic basis. 3. Collapse pressure is 1500 psi above the Mount Goodwin gas to surface pressure which is the maximum feasible surface pressure (Worst Case 13 5/8" casing collapse pressure is based on a simultaneous production packer failure and the highest gas pressure in the 20"x13 5/8" annulus). 4. Full evacuation to gas prevented as TTOC inside 20"x13 5/8" annulus is 644m which is 305m inside 20" shoe. ScanWell leak and fluid level surveys confirmed leak is one way with gas able to migrate up through the cement micro annulus but fluid unable to leak off to the formation. 5. No CO2 or H2S is detected in the produced gas, therefore the corrosion risk is minimal.	1	A	Low
		Environment			1	B	Low		1	A	Low
		Cost/ Business Loss			3	C	Medium High	**Mitigating Controls** 1. Well services team is mobilised to WHP within 24hrs to investigate and bleed down annulus pressure when the alarm limit of 780 psi is reached 2. 20" Casing and wellhead rated to a minimum pressure of 3060 psi (20" casing burst) which is above the maximum expected reservoir pressure.	3	A	Low
		Corporate Image			3	C	Medium High		3	A	Low

ID #	Activity	Applicability	Hazard	Consequence	Risk Severity	Risk Prob	Risk Rating	Existing Prevention or Mitigation Controls	Risk Severity	Risk Prob	Risk Rating
No	Risk	Personnel, Environment, Damage Schedule	Risk description	Risk Impacts	Original risk			Prevention – prevent hazard event occurring & reduce the likelihood of event. Mitigation - reduces the consequence.	Mitigated risk		
4	P3 Production with 20"x13 5/8" annulus micro annulus and sustained casing pressure	People H&S	20"x13 5/8" annulus outlet valve failure during unmanned production activities	1. Loss of containment 2. Short duration jet fire release of gas followed by low level gas leak at approx. 4.55 scf/min Reservoir (primary and secondary barriers unaffected).	1	A	Low	**Preventative Measures** 1. Smart VR Plugs and MSAS to be installed on both outlets Two barriers on both outlets. 2. Annulus pressure continuously monitored in the Yelcherr gas plant control room. 3. 20"x13 5/8" annulus pressure alarms automatically trigger if MAWOP is exceeded. (Note: the alarm is set at 780psi, while MAWOP is 1,159psi). 4. . TFMC UH4 Unihead outlet valve rated to 5000psi 5. Wellhead and HXT maintenance and testing schedule ensures barrier effectiveness. 6. Full evacuation to gas prevented as TTOC inside 20"x13 5/8" annulus is 644m which is 305m inside 20" shoe. ScanWell leak and fluid level surveys confirmed leak is one way with gas able to migrate up through the cement micro annulus but fluid unable to leak off to the formation. Fluid level 5m below wellhead limiting gas volume	1	A	Low
		Environment			1	A	Low		1	A	Low
		Cost/ Business Loss			3	B	Medium	**Mitigating Controls** 1. A failure of the 20" casing outlet valve does not impact the reservoir primary and secondary barrier envelopes, both remain intact. 2. Well Shut in and TRSV closed when WHP fire and gas system is activated. 3. Low level 4.55 scf/min leak unable sustain a flame or explosive environment after initial release.	2	A	Low
		Corporate Image			3	B	Medium		2	A	Low
5	P3 Production with 20"x13 5/8" annulus micro annulus and sustained casing pressure	People H&S	20"x13 5/8" annulus outlet valve failure during manned WHP activities, Dropped object or incorrect maintenance procedures	1. Loss of containment 2. Short duration jet fire release of gas followed by low level gas leak at approx. 4.55 scf/min 3. Single Fatality (Reservoir primary and secondary barriers unaffected)	4	B	Medium High	**Preventative Measures** 1. Dropped object protection to be installed over 20"x13 5/8" annulus outlet during well services activities. 2. Two barriers in place , (Smart VR plug and MSAS installed on both outlets) 3. TFMC UH4 Unihead outlet valve rated to 5000psi 4. Wellhead and HXT maintenance and testing schedule ensures barrier effectiveness 5. Full evacuation to gas prevented as TTOC inside 20"x13 5/8" annulus is 644m which is 305m inside 20" shoe. ScanWell leak and fluid level surveys confirmed leak is one way with gas able to migrate up through the cement micro annulus but fluid unable to leak off to the formation.	2	A	Low
		Environment			1	B	Low		1	A	Low
		Cost/ Business Loss			3	B	Medium	**Mitigating Controls** 1.No Personnel to be adjacent to 20"x13 5/8" annulus outlet when installing and removing pressure control equipment or well servicing activities. 2. A failure of the 20" casing outlet valve does not impact the reservoir primary and secondary barrier envelopes, both remain intact. 3. Well Shut in and TRSV closed when WHP fire and gas system is activated. 4. Low level 4.55 scf/min leak unable sustain a flame or explosive environment after initial release.	2	A	Low
		Corporate Image			3	B	Medium		2	A	Low
6	P3 Production with 20"x13 5/8" annulus micro annulus and sustained casing pressure	People H&S	Disconnection of communication between WHP and YGP/Perth for alarm/annulus pressure monitoring.	1. Loss of containment	1	c	Low	**Preventative Measures** 1. Primary system UPS 2. Backup independent communication system available from WHP to YGP.	1	A	Low
		Environment			1	A	Low		1	A	Low
		Cost/ Business Loss			1	B	Low	**Mitigating Controls** 1. Wells Shut in if all communications lost (ESD system) 2. Helicopter contract in place for urgent dispatch of personnel from YGP to the WHP to allow for prompt response to alarms.	1	A	Low
		Corporate Image			1	A	Low		1	A	Low
7	P&A	Environment	Ineffective Rock to Rock permanent barrier	1. Hydrocarbon leakage to the environment	3	B	Medium	1. Current well design supports placement of well barriers to A1 Mount Goodwin, A1 fossil head and A2 to A6.5 reservoirs (Keyling and Treachery). - Milling or PWC of the 13-5/8" casing x 17.5" annulus would be required to address the annulus pressure should it exist at the end of well life. Depending on the extent of the flow (expected to be low based on the steep decline of the pressure during the first bleed off), a detailed plan to address this issue during P&A, under well control,will be drawn. Note: P&A requires laterally extensive barrier for A1 Mount Goodwin formation at a depth no shallower than 590m TVDSS, for A1 fossil head at a depth no shallower than 1050m and for A2 to A6.5 at a depth no shallower than 1750m TVDSS.	2	B	Low