DIMENSION BID

PETRONAS

ANGSI A-24L
METHANOL SOAKING & WELL UNLOADING

Revision:	1
Prepared for:	Arsyamimi Bt Mohamed
Date Prepared:	29th Nov 2022
Well:	A-24L
Field:	Angsi
Operation Region:	PMA
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DESIGN VERIFICATION

		29/11/2022
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		29/11/2022
APPROVED BY DB CTS Operation Manager	Aliff Amirul Adenan	Date
APPROVED BY PCSB Angsi Well Intervention Engineer	Arsyamimi Bt Mohamed	Date
APPROVED BY PCSB Technical Professional Well Intervention, PMA	Azwan B Muhammad Kifli	Date
APPROVED BY PCSB Head of Cluster 1 Well Intervention, PMA	M Azza B Zaini	Date

Remark: Do not execute the procedures in this document if it is not fully approved and signed by all parties.

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REVISION HISTORY

Rev. No	Section	Date	Revised By
0	All	27/11/2022	Muhd Ameerul Zaeem
1	To update CT String Pipe Tracking Management	29/11/2022	Muhd Ameerul Zaeem

ACRONYM

Acronym	Abbreviation
BHA	Bottom Hole Assembly
RIH	Run In Hole
POOH	Pull Out Of Hole
HUD	Hang Up Depth
TCC	Tubing Clearance Check
ZSO	Zone Shut Off
SCO	Sand Clean Out
TIT	Tubing Integrity Test

BOP	Blow Out Preventer
CT	Coil Tubing
ID	Internal Diameter
MDTHF	Measure Depth Tubing Head Flange
SSD	Sliding Side Door
P&A	Plug and Abandonment
MASTP	Maximum Allowable Surface Treating Pressure
STP	Surface Treating Pressure

TABLE OF CONTENT

OBJECTIVES

The objective of this job is:

1. To perform methanol soaking at I-100 perforation section to treat condensate in the zone.
2. To perform well unloading via Coil Tubing to unload liquid held up inside tubing until across I-100 Top Perf interval.

BACKGROUND

Angsi-A24 is a dual gas producer which was completed on Nov 2003 with maximum deviation of 69.22 degree at 1,123m MDDF. Currently the well is unable to flow post ESD in Aug 2022 and had high liquid level which reported at 3,500m MDDF with reservoir pressure reported at 734 psi (I-100) based on SGS conducted on Sept 2022. This job program will execute to perform methanol soaking via CTU at I-100 zone and displace wellbore fluid with N_2 until across I-100 perforation section at 3,653 m / 11,985 ft MDDF.

WELL DATA

Input Parameter	Parameter Value
Field	Angsi-A24
Max. Deviation (degrees)	69.22 degree @ 1,123m MDDF
Min. Restriction (inch)	**2.69” (XN Nipple) @ 3,392.83m MDDF (Long String)**
Tubing Specification	3-1/2” Production Tubing, 9.2# ppf, 13Cr
Type of Fluid & Density	9.2 PPG NaCl (based on Completion Fluid data in Well Diagram)
Top of Fluid	3,500m MDDF / 11,483ft MDDF
Current Well Status	Idle
Depth of zone	I-100: 3,603m – 3,653m MDDF
Reservoir Pressure	734 psi
Reservoir Temperature	260 deg F
Porosity	18%
Permeability	161 mD
Fracture Gradient	0.70psi/ft

Additional Information / Notes / Special Requirement:

- Top of fluid recorded by slickline during SGS at 3,500m MDDF / 11,483ft MDDF (Sept 2022)
- Latest Slickline HUD at 3,656 m MDDF / 11,995 ft MDDF (Nov 2022)

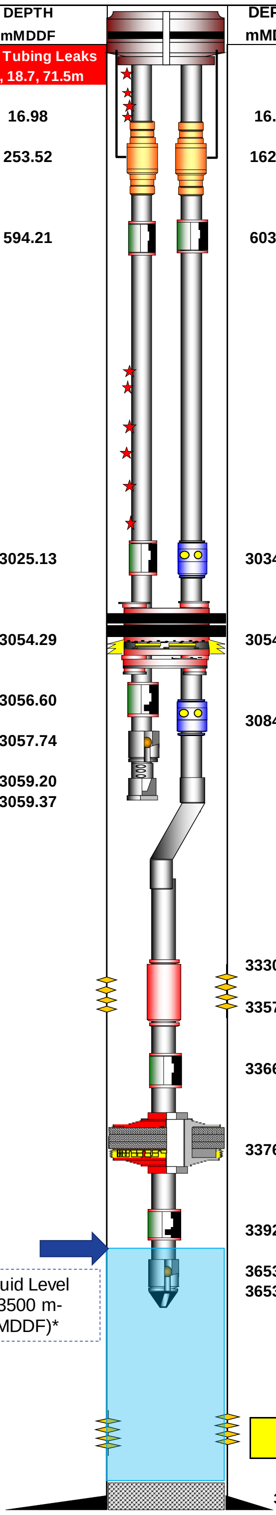
OPERATION SUMMARY

Item	*Job Description*	*Remark*
A	Slickline	1. RIH FOR TCC & SGS
B	Coiled Tubing Operation	1. RUN #1: DEPTH CORRELATION WITH MULTIJET NOZZLE C/W 2.75 FLUTED CENTRALIZER UNTIL XN-NIPPLE AND PERFORM METHANOL SOAKING 2. RUN #2: N2 UNLOADING

DIMENSION BID	DIMENSION BID COILED TUBING SERVICES		PETRONAS
	ANGSI-A24L	WELL UNLOADING	

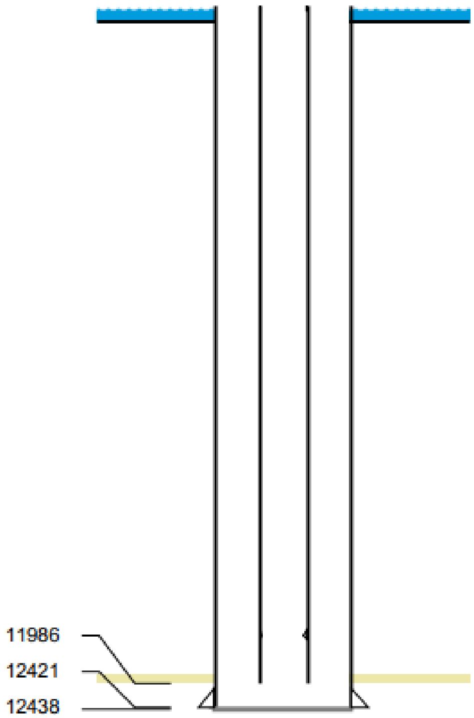
WELL DIAGRAM

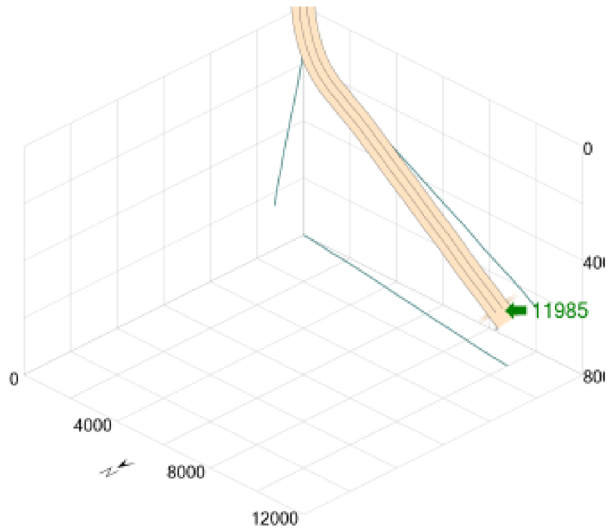
ANGSI A-24 DUAL WI & GP			PCSB - EPMI
BLOCK / FIELD	GPSC / ANGSI - A	COMPLETION DATE	31/10/2003
WELL NAME / LOCATION	ANGSI A-24/ LOC. I68-5	WELL TYPE / MAX ANGLE	B & HOLD / 69.22° AT 1123.8 MMD
PLATFORM / SLOT	ANDR-A / SLOT NO:42	COMPL / PACKER FLUID	NaCl 9.2 PPG / NaCl 9.2 PPG
RIG TYPE / NAME	TENDER / TIOMAN - 6	COMPL EQUIPMENT/ X-MAS TREE	HALLIBURTON / CAMERON
WATER DEPTH / DF ELEV	69 METER / 33.9 M AMSL	DRILL FLOOR - THF	16.9 M



SHORT STRING 3-1/2", 9.2PPF, L-80 13-Cr, FOX			DEPTH mMDDF	DEPTH mMDDF	DEV (°)	SINGLE STRING 3-1/2", 9.2PPF, L-80 13-Cr, FOX		
EQUIPMENT	MIN ID IN	MAX OD IN				EQUIPMENT	MIN ID IN	MAX OD IN
TUBING HANGER	2.823	11.000	16.98	16.98	0.3	TUBING HANGER	2.823	11.000
FLOW COUPLING	2.992	4.150				FLOW COUPLING	2.992	4.150
TR-SCSSSV	2.813	5.030	253.52	162.74	14.1	TR-SCSSSV	2.813	5.030
FLOW COUPLING	2.992	4.150				FLOW COUPLING	2.992	4.150
X NIPPLE	2.813	3.960	594.21	603.47	44.6	X NIPPLE	2.813	3.960
X NIPPLE	2.813	3.960	3025.13	3034.34	63.8	XD-SSD (CLOSED)	2.813	4.550
9 5/8" BHD DUAL PACI (S/S SET)	2.820	8.457	3054.29	3054.29	64.5	9 5/8" BHD DUAL PACK (S/S SET)	2.820	8.457
XN- NIPPLE	2.690	3.960	3056.60					
				3084.70	64.8	XD-SSD (CLOSED)	2.813	4.550
POP ASSY	2.871	3.970	3057.74					
CATCHER SUB	-	3.920	3059.20					
END OF TUBING			3059.37		64.5			
I - 35 RES FUTURE GAS PRODUCER								
				3330.06	65.30	BLAST JOINT	2.880	4.115
I - 68 RES WATER INJECTOR 3335.0 - 3351.0 mMDDF				3357.05	65.10			
				3366.19	65.0	X-NIPPLE	2.813	3.960
				3376.56	64.6	9-5/8" BHR HYD PKR	4.000	8.340
				3392.83	64.0	XN NIPPLE	2.690	3.960
				3653.08		POP ASSY	2.880	3.920
				3653.25	60.1	END OF TUBING		
I - 70 RES - FUTURE GAS PRODUCER								
I - 100 RES - GAS PRODUCER 3603.0 - 3653.0 mMDDF				I - 100 RES - GAS PRODUCER 3603.0 - 3653.0 mMDDF				
		Last intervention Apr 08 MIT		3786.0	58.6	9-5/8" CASING SHOE		

WELL 3D PLOT





Well name: Angsi A24L
Total depth: 12438 ft
Max Inclination: 69.2° at 3687 ft
Max DLS: 5.171 °/100ft at 2362 ft
Min ID: 2.690 in at 11131 ft
WHP: 150 psi

Input Parameter	*Parameter Value*
Field	ANGSI ANDRA
Trajectory Until Depth	3,749 m MDDF / 12,300 ft MDDF (PBTD)
Max. Deviation (degrees)	69.2 degree at 3,687m MDDF
Min. Restriction (inch)	2.69” @ 3,392 m MDDF

COMPLETION VOLUME

Description	Details
Tubing Specification	3-1/2", 9.2#, 13Cr
Prod. Casing Specification	9-5/8", 40#, 13Cr

Tubing - Long String

Type	External Pipe			Internal Pipe			Internal Pipe			Caps	From	To	From	To	Length	Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	Barrel/lin (ft)	m	m	ft	ft	ft	
THF to SSD#1	3 1/2	2.992	9.2							0.00870	16.98	3034.34	56	9956	**9900**	**86**
SSD#1 to SSD #2	3 1/2	2.992	9.2							0.00870	3034.34	3084.70	9956	10121	**165**	**1**
SSD #2 to I-100 Top Perf	3 1/2	2.992	9.2							0.00870	3084.70	3603.00	10121	11821	**1701**	**15**
I-100 Top Perf to Bottom Perf	3 1/2	2.992	9.2							0.00870	3603.00	3653.00	11821	11985	**164**	**1**
I-100 Bottom Perf to EOT	3 1/2	2.992	9.2							0.00870	3653.00	3653.25	11985	11986	**1**	**0**
															TOTAL	**104**

A-Annulus (PCP)

Type	External Pipe			Internal Pipe			Internal Pipe			Caps	From	To	From	To	Length	Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	Barrel/lin (ft)	m	m	ft	ft	ft	
THF to Packer#1	9 5/8	8.835	40	3 1/2	2.992	9.2	3 1/2	2.992	9.2	0.05203	16.98	3054.29	56	10021	**9965**	**518**

B-Annulus (PCP)

Type	External Pipe			Internal Pipe			Internal Pipe			Caps	From	To	From	To	Length	Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	Barrel/lin (ft)	m	m	ft	ft	ft	
Packer #1 to EOT SS	9 5/8	8.835	40	3 1/2	2.992	9.2	3 1/2	2.992	9.2	0.05203	3054.29	3059.37	10021	10038	**17**	**1**
EOT SS to Packer #2	9 5/8	8.835	40	3 1/2	2.992	9.2				0.06393	3059.37	3376.56	10038	11078	**1041**	**67**
															TOTAL	**67**

Wellbore Area on I-100 Reservoir

Type	External Pipe			Internal Pipe			Internal Pipe			Caps	From	To	From	To	Length	Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	Barrel/lin (ft)	m	m	ft	ft	ft	
Packer#2 to I-100 Top Perf	9 5/8	8.835	40	3 1/2	2.992	9.2				0.06393	3376.56	3603.00	11078	11821	**743**	**47**
I-100 Top Perf to Bottom Perf	9 5/8	8.835	40	3 1/2	2.992	9.2				0.06393	3603.00	3653.00	11821	11985	**164**	**10**
I-100 Bottom Perf to EOT	9 5/8	8.835	40	3 1/2	2.992	9.2				0.06393	3653.00	3653.25	11985	11986	**1**	**0**
EOT to PBTD	9 5/8	8.835	40	3 1/2	2.992	9.2				0.06393	3653.25	3749.00	11986	12300	**314**	**20**
															TOTAL	**78**

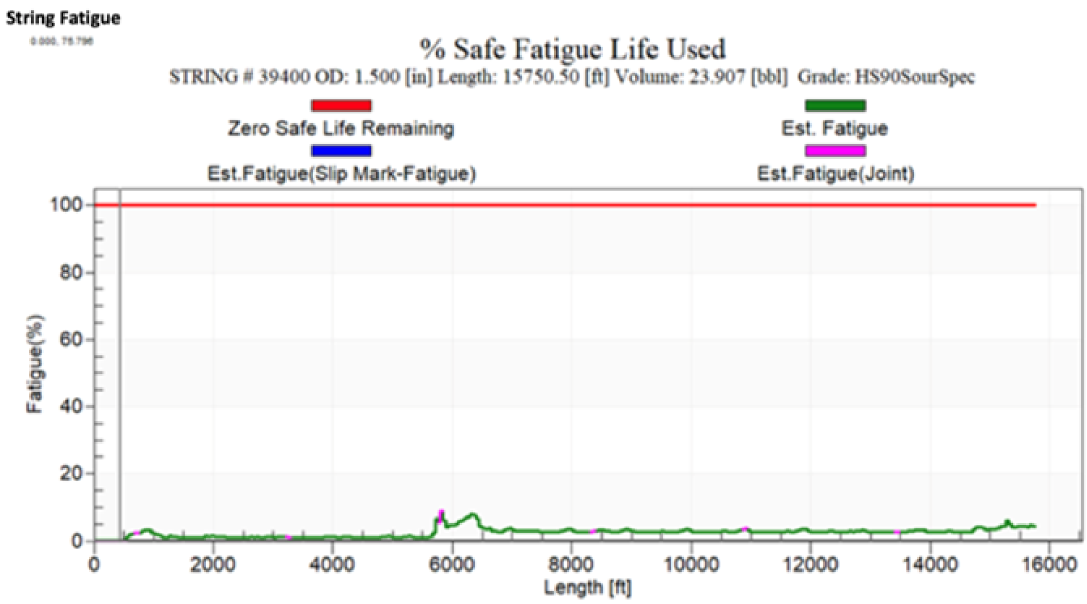
Chemical Volume into Formation I-100

Type	External Pipe			Internal Pipe			Penetration	Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	(in)	Barrel/lin (ft)	m	m	ft	ft	ft	
I-100		57.625		9 5/8			24	3.13568	3603.00	3653.00	11821	11985	**164**	**514**
													Porosity	**0.18**
													Total	**92.6**
											TOTAL PENETRATION VOLUME			**92.6**

COILED TUBING STRING INFORMATION

OD (in)	Spec	W/T (in)	ID (in)	Length (ft)
1.5	Tenaris	0.125	1.25	14,535
CT Volume: 22.2 bbls				

CT STRING FATIGUE



CT STRING #HS39400 LATEST PIPE MANAGEMENT

Run #	Date	Client Name	Field Name	Well Num	Job type	Running ft ft	Cum. Run ft	Max CTW lb	Max CTP psi	Chrome Y/N	New CT leng ft	Cum Running in Chrome ft	Job Fatigue %	Job Corrosion %	Max Fatigue %	Cum. Corrosion %	Used String Life %
1	2/1/2021					NA	NA	NA	NA	NA	15,799	NR					
2	5-Jan-21			A13L	CT MECHANICAL	NR	NR	NR	NR	NR	15,789	NR					
3	5-Feb-21			A13L	CT MECHANICAL	NR	NR	NR	NR	NR	15,788	NR					
4	2-Apr-21			A16L	CT MECHANICAL	NR	NR	NR	NR	NR	15,786	NR					
5	6-Sep-21			A5U	CT WELL CLEANOUT	NR	NR	NR	NR	NR	15,784	NR					
6	27-Oct-21					NR	NR	NR	NR	NR	15,775	NR					
7	2-Nov-21			A16L	FISHING	NR	NR	NR	NR	NR	15,770	NR					
8	2-Nov-21			A16L	CT FILL/SCP	NR	NR	NR	NR	NR	15,770	NR					
9	2-Nov-21			A16L	FISHING	NR	NR	NR	NR	NR	15,750	NR	NR	12	8.8	12	20.8
RECEIVED CT STRING AT OPEN DB YARD																	
10	17-Jun-22				CUT CT COIL AT OPEN YARD DB	NA	NA	NA	NA	NA	15,740	NA	NA	0	8.8	12	20.8
11	30-Jun-22	PCSB	DULANG	A-4L	RUN#1 DRIFT RUN UNTIL 8298FT	9283	9283	NA	NA	Y	15,713	9283	1.65	0.5	10.52	12.5	23.02
12	1-Jul-22	PCSB	DULANG	A-4L	RUN#2 CLOSE SSD USING 2.813" KEY SHIFTING TOOL	8764	18047	NA	NA	Y	15,713	18047	1.63	0.5	11.87	13	24.87
13	3-Jul-22	PCSB	DULANG	A-4L	RUN#3 DRIFT RUN UNTIL SSD#3	11404	29451	NA	NA	Y	15,703	29451	1.68	0.5	12.15	13.5	25.65
14	4-Jul-22	PCSB	DULANG	A-4L	RUN#4 DEPTH CORRELATION WITH GRCCL	11284	40735	NA	NA	Y	15,703	40735	0.1	0.5	12.15	14	26.15
15	5-Jul-22	PCSB	DULANG	A-4L	RUN#5 SET BRIDGE PLUG	10,888	51623	NA	NA	Y	15,703	51623	0.5	0.5	12.43	14.5	26.93
16	7-Jul-22	PCSB	DULANG	A-4L	RUN#6 WLD BASE LINE	10887	62510	NA	NA	Y	15,603	62510	0.49	0.5	12.7	15	27.7
17	9-Jul-22	PCSB	DULANG	A-4L	RUN#7 WLD ACTIVE LEAK PASS	13339	75849	NA	NA	Y	15,603	75849	0.83	0.5	13.23	15.5	28.73
18	11-Jul-22	PCSB	DULANG	A-4L	RUN#8 RUN CEMENTING	11803	87652	NA	NA	Y	15,603	87652		0.5	13.23	16	29.23
19	12-Jul-22	PCSB	DULANG	A-4L	TRIM COIL POST JOB CEMENTING	NA	NA	NA	NA	NA	15,503	NA		0	13.23	16	29.23
20	17-Jul-22	PCSB	DULANG	A-4L	RUN#9 RUN TAG TOC	10805	98457	10200	1800	Y	15,503	98457	0.74	0.5	13.49	16.5	29.99
21	21-Jul-22	PCSB	DULANG	A-4S	RUN#1 SCO UNTIL EOT 2489MTR	10850	109307	9200	3240	Y	15,503	107,526	1.31	0.5	14.27	17.5	31.77
22	22-Jul-22	PCSB	DULANG	A-4S	RUN#2 N2 KICK OFF	9489	118796	8150	1200	Y	15,503	118796	0.87	0.2	14.66	17.7	32.36
23	31-Jul-22	PCSB	DULANG	A-4S	RUN#3 N2 KICK OFF	12631	131,427	15300	1230	Y	15,503	131,427	1.74	0.3	15.51	18	33.51
24	29-Aug-22	PCSB	ANGSI	D-04S	TRIM PRIOR CTU OPERATION	12631	131,427	15300	1230		15,450	131,427	1.74	0.3	15.51	18	33.51
25	1-Sep-22	PCSB	ANGSI	D-04S	RUN#1: SCO	7728	139,155	11000	2868	N	15,450	0	1.56	0.3	17.07	18.3	35.37
26	3-Sep-22	PCSB	ANGSI	D-04S	RUN#2: Depth Correlation & Stimulation	8265	147,420			N	15,450	0	1.46	0.5	18.53	18.8	37.33
27	5-Sep-22	PCSB	ANGSI	D-04S	RUN#3: Stimulation	11882	159,302			N	15,450	0	0.99	0.5	19.52	19.3	38.82
28	8-Sep-22	PCSB	ANGSI	D-04S	Cut 160ft coil	NA	NA	NA	NA	NA	15,290	0	0	0	19.52	19.3	38.82
29	9-Sep-22	PCSB	ANGSI	D-04S	Cut 200ft coil	NA	NA	NA	NA	NA	15,090	0	0	0	19.52	19.3	38.82
30	5-Oct-22	PCSB	ANGSI	D-02L	RUN#1: SCO	14390	173,692	15050	4490	N	15,090	0	1.01	0.5	20.53	19.8	40.33
31	7-Oct-22	PCSB	ANGSI	D-02L	RUN#2: SCO	14791	188,483	34000	4262	N	15,090	0	2.46	0.5	22.99	20.3	43.29
32	8-Oct-22	PCSB	ANGSI	D-02L	Cut 50ft coil	NA	NA	NA	NA	NA	15,040	0	0	0	22.99	20.3	43.29
33	13-Oct-22	PCSB	ANGSI	D-02L	RUN#3: SCO	19576	208,059	24000	4800	N	15,040	0	6.04	0.5	26.57	20.3	46.87
34	16-Oct-22	PCSB	ANGSI-A	D-02L	RUN#4: SCO	18210	226,269	16200	4500	N	15,040	0	3.79	0.5	26.78	20.8	47.58
35	16-Nov-22	PCSB	ANGSI		CUT COILED AT ANGSI ANDRA (505FT)	NA	NA	NA	NA	NA	14,535	0	0	0	22.99	20.3	43.29
36	18-Nov-22	PCSB	ANGSI	A-08L	CT RUN#1 SCALE CLEANOUT	13393	239,662	22,000	4250	Y	14,535	144,820	1.55	0.5	24.54	20.8	45.34

Based on above pipe management;

- Current CT Fatigue Life is 24.54%
- Current String Used Life is 45.34%
- Current Running Footage in Chrome Completion is **144,820 ft**
- Current Total Running Footage is 239,662 ft

Based on Dimension Bid Standard Operating Procedure (SOP) of Pipe Management for Chrome Completion;

- Max Running Footage in Chrome Completion is **200,00ft**

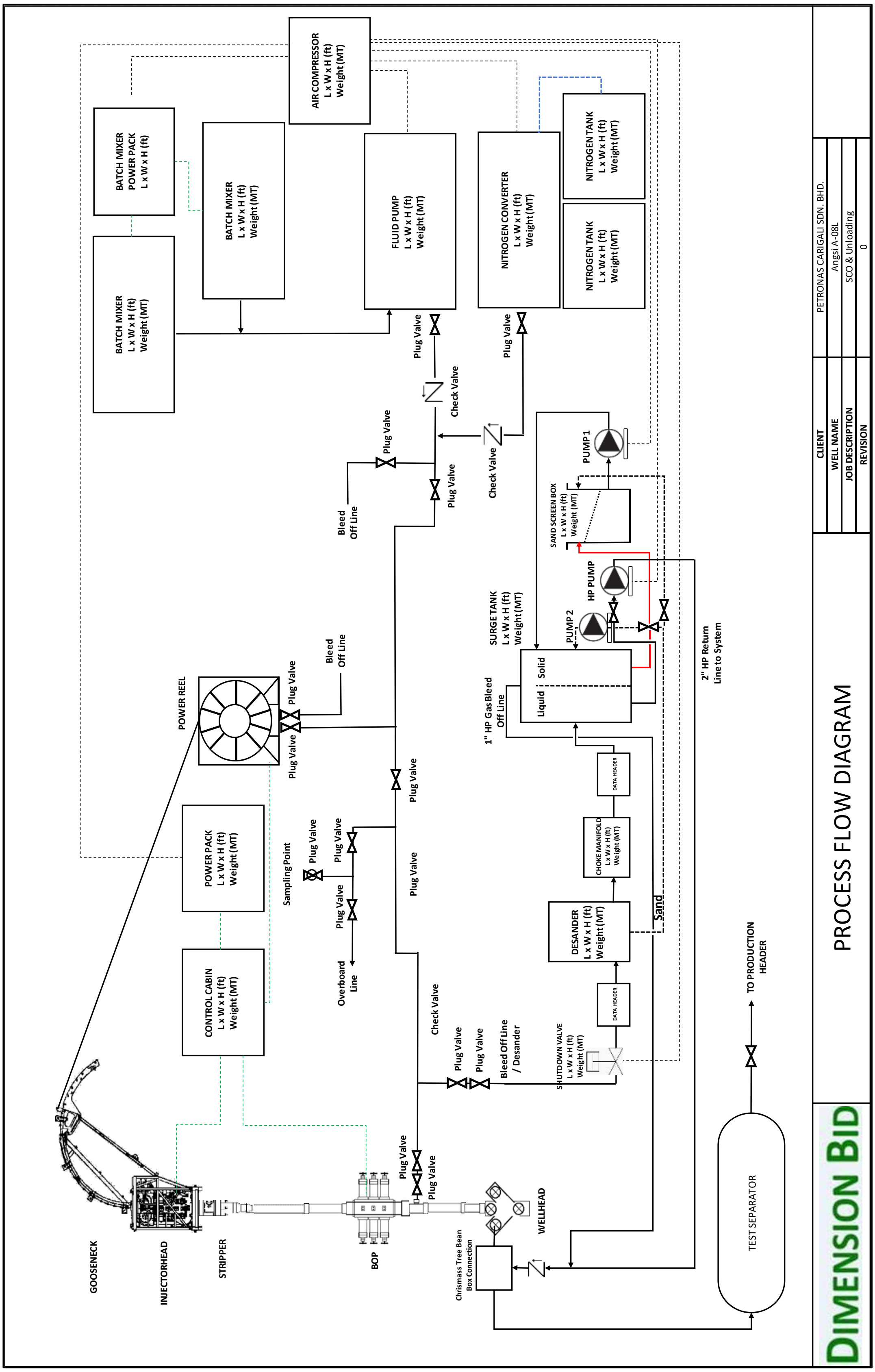
Based on Dimension Bid Standard Operating Procedure (SOP) of Pipe Management to junk the coil;

- **100%** of Ct String Life reached
- Experienced two separate pinholes for the same CT String
- CT String exceed max working pressure

MAXIMUM ALLOWABLE SURFACE TREATING PRESSURE (MASTP)

Fluid	Fluid Density, ppg	Fluid Column until Mid Perf. TVD, ft	Hyd. Pressure, psi	Fracture Pressure, psi	STP, psi	80% MASTP, psi
Treated Fresh Water (TFW)	8.46	6,205	2,730	4,344	1,614	1,300
Treated Injection Water	8.58	6,205	2,768	4,344	1,576	1,300
Methanol	8.34	6,205	2,691	4,344	1,653	1,300

PROCESS FLOW DIAGRAM



SAFETY OPERATIONAL PROCEDURES

Prior to commencement of the Coiled Tubing / Bull-heading operation, a pre-job meeting will be held. This should be attended by the following parties as a minimum:

OIM, WSS, Coiled Tubing Supervisor, Representatives of other service companies involved and others as necessary.

Safety meetings should be held at the start of every shift and risk assessments must be evaluated during this time. Tool box talks should be held immediately prior to the job execution.

Note: The safety meeting must be driven by DB Supervisor addressing the following topics as a minimum:

1. Muster point.
2. Take list of personnel on site (Head count)
3. All personnel should review and be familiar with escape routes and emergency procedures.
4. Describe the **job objective, fluids and volumes to be pumped, pressures expected** during the job, and others.
5. Review **Dimension Bid Operations Policy and Procedure Manual.**
   - 5.1. Ensure at all steps carried out during the operations comply with this Manual.
   - 5.2. Management of change MUST be applied any time there is a need to deviate from the steps contained this procedure.
   - 5.3. A document MUST be created describing each the step of the deviation. This document shall also include the deviation Risk Assessment and it MUST be approved and signed by PCSB – Head of Well Intervention and Dimension Bid Operations Manager.
6. Exercise stops work authority if unsafe condition occurs and assess situation with all team members, resume operation after mitigation plan is in place.
7. Personnel responsibilities throughout the job.
8. Spills, fire, blow out, unexpected well behaviour.
9. Emergency shower station and eye wash station location.
10. Trapped potential energy such as pressure or coiled tubing stiffness.
11. Prepare related Job Hazard Analysis (JHA) prior commencement of any work, get approval from Client Site Representative (CSR) and review it with all personnel involved as well as to review Risk Assessment.
12. Discuss the well H_2S, CO_2, Hg (Mercury) content (if applicable).
13. Adhere all **PCSB Zeto Rules** and other guidelines.
14. Take a physical count of inventory and make sure all required materials are available on site.
15. **Barricade** the work area and display the appropriate **warning sign**.
16. On chemical mixing and handling; all personnel involved shall hold **safety meeting** and review **Safety Data Sheet** (SDS).
   - 16.1. Personnel involve during chemical handling shall be briefed by DB Chemical Specialist onsite and extra precautions must be taken. All SDS must be available on site and reviewed prior chemical handling.
   - 16.2. All non-essential personnel shall stay away from mixing site.
   - 16.3. Use PPE including respirators, hard hats, eye protection and steel-toed boots.
   - 16.4. Verify if there is any **dead Volume** in the mixing tanks and adjust volumes to account for non-usable volume in the blender / mix tank.

16.5. Consider wind direction and note all trip hazards in the mix / pumping area.

16.6. Prior to mixing chemicals, clean and verify the tank/batch mixer and lines are free of any debris and or contaminants.

16.7. In case of spill; wash the place where any chemical has been spilt with available spill kit.

16.8. Take care to prevent leakage due to ejection from valves, fittings, flanges, or other joints flexible chemical hoses and pumps. Never repair the equipment during transfer into mixing tank/container.

17. Take reading of Shut in / Flowing Tubing Head Pressure (SI/FTHP), Casing Head Pressure (CHP) and fluid sample (if available) prior to operation.
18. Check gas lift condition and capability with Site Operation Representative (SOR).
19. Ensure fitness prior to perform duties assigned.
20. Ensure all barriers are in place and followed.

HEALTH, SAFETY & ENVIRONMENT

1. Evaluate possible risks to arise during the job execution.
2. Evaluate risk assessment. Report any abnormal or insecure condition on site, taking into account all the steps or procedures to follow. Discuss with PCSB HSE coordinator, the execution or suspension of the job.
3. Review SDS of each product that will be used. Verify that all personnel on location handling toxic or corrosive products have the proper PPE.
4. Review the contingency plan for spills.
5. Do not vent / release any hydrocarbons from the well to atmosphere. Returns from the well should be handled safely by Cetco Flowback Company.
6. Prior to DB personnel walking on upper deck, DB Supervisor to inspect upper deck and ensure that the area it is in good condition (Gratings, Hatches, etc.)

EQUIPMENT RIG UP PROCEDURE

Conduct safety meeting with all personnel on location detailing the program, pressure limitations, and personnel responsibilities, well control emergency drill and safety precautions.

1. Spot the equipment accordingly to space availability, ensure reel position is aligned with the well.
2. Spot jacking frame at available space with sufficient height and crane capacity to rig up the injector head and gooseneck.
3. Rig up the 4” LP hoses from fluid storage tanks to batch mixer and single pump unit
4. Rig up 2” HP treating line as per DB Technical Standard from single pump unit and N2 converter unit to coiled tubing reel manifold. Include bleed off line on both lines as well.
5. Install correct wellhead crossover on the wellhead. Ensure well is fully secure and record the MV and CV turns.
6. Install Blowout Preventer (BOPs):
   6.1. Rig up Single BOP with necessary length of risers on top of the wellhead crossover.
   6.2. Rig up Combi BOP with flow tee above the risers
   6.3. Hook up BOP hoses and conduct function test for each ram.
7. Rig up 2” kill line from single pump unit line to BOP kill port
8. Rig up flow back line from flow tee to Choke manifold -> desander unit / production system
9. Spot injector head assembly with jacking frame on top of wellhead area. Ensure the gooseneck is aligned with the reel position
10. Inspect the chain and gripper block condition and ensure the alignment is correct
11. Rig up the following hydraulic hoses:
    11.1. From CT Power Pack to CT Control Cabin
    11.2. From CT Power Pack to CT Injector hose reel
    11.3. From CT Control Cabin to CT Reel
    11.4. From CT Control Cabin to CT BOPs
    11.5. From CT Power Pack to Jacking Frame
12. Perform EMC 1 for all equipment. Start up and run all equipment for few minutes.
13. Jack up CT control cabin.
14. Function test both BOP rams.

    *Observe indicator pin to confirm that all rams are in good working condition.
15. Install the stab-in-guide on the CT then stab the string into injector head.
16. Make up the CT connector and perform pull test at least 15,000 lbs as per DB SOP. This test to be recorded in OrionNet.

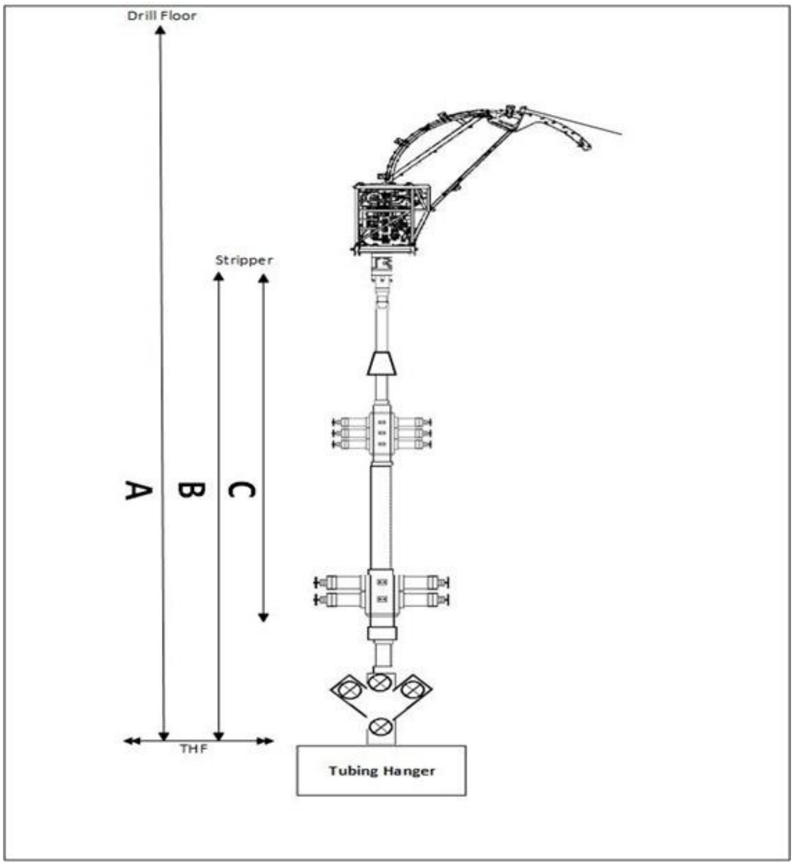
    *Do not perform pull test more than 80% from CT Limit. (38,880 lbs)
17. Install pressure test plate onto the CT connector.
18. Circulate the string with water until clean return is seen prior to proceed with pressure test CT Connector.
19. Pressure up the CT string to 5000 psi gradually by 500 psi increment then hold for 10 minutes. Pressure test acceptance criteria:
    19.1. For low pressure at 300 psi:

Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 270 psi) over 5-minutes test interval after the pressure stabilizes.

19.2. For high pressure at 5000 psi:

Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 4,500 psi) over the 15- minutes test interval after the pressure stabilizes

20. Open the needle valve to release the pressure slowly.
21. Make up the BHA onto the string as per BHA diagram provided.
22. Use the jacking frame to pick up the injector and risers then connect to the Combi BOP. Secure down the injector assembly with chains.
23. Measure the following length to set the CT depth:



Distance	Length (ft)
A: Tubing Hanger (THF) to RKB	
B: Tubing Hanger (THF) to Stripper	
C: BHA Length	

*The reference depth is at the tip of BHA

24. Pick up CT and tag the stripper to set CT depth based on this calculation “A-B+C”.

EQUIPMENT PRESSURE TESTING PROCEDURE

Conduct safety meeting with all personnel on location detailing the program, pressure limitations, and personnel responsibilities, well control emergency drill and safety precautions. Refer the following procedure to pressure test BOP Body, Blind Ram, Surface Line and Wellhead connection.

1. Isolate the line to Coiled Tubing. Double confirm the valve is closed.
2. Fill and pressure test the treating line with water to 500 psi and hold for 5 minutes. Inspect the lines for leaks and observe for any pressure drop.
3. Increase pressure to 3000 psi and hold for 10 minutes. Inspect the lines for leaks and observe for any pressure drop.
4. Fill the pressure control equipment and ensure air is vented from the system by leaving the blind ram and blind ram equalizing valves open.
5. Close blind ram and equalizing valve. Pressure up the surface lines, BOP body, blind rams and wellhead connection to 500 psi then increase gradually to 3000 psi through the kill line, hold for 10 minutes. Inspect the lines for leaks and observe for any pressure drop. PT acceptance criteria as per below:
   5.1. For low pressure at 500 psi:

   Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 450 psi) over 5-minutes test interval after the pressure stabilizes.

   5.2. For high pressure at 3000 psi:

   Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 2,700 psi) over the 15- minutes test interval after the pressure stabilizes
6. Once test complete, open blind ram pressure equalizing port then bleed off any residual pressure and open the blind rams.

Conduct safety meeting with all personnel on location detailing the program, pressure limitations, and personnel responsibilities, well control emergency drill and safety precautions. Refer the following procedure to pressure test BOP Body, Blind Ram, Surface Line and Wellhead connection.

1. Fill up the CT string and stack up until leak can be seen at stripper.
2. Energize the stripper and begin pressure test the complete stack up (CT string, stripper, CT stack and risers) to 3000 psi against Crown Valve, hold for 10 minutes.
3. Bleed off pressure inside stack up to 1,500 psi and bleed off pressure inside CT to 0 psi to test the Double Flapper Check Valve to 1500 psi and hold for 10 minutes. Do not apply pressure more than CT Collapse Pressure (1500 psi)
4. Bleed off the pressure from BOP kill port side.

   *Step 4-8 can be neglected if pipe ram has been pressure tested prior to the job.
5. Place CT string across pipe ram then close the ram.
6. Open pipe ram equalizing valve then fill up the BOP slowly.
7. Close the equalizing valve and begin pressure test the pipe ram to 3000 psi, hold for 10 minutes.
8. When the tests are complete, bleed off the pressure.

CT STRING MANAGEMENT DURING OPERATION

1. When RIH CT String in 13CR Chrome Completion, there are few mitigations plan need to be executed throughout the CT Operation to ensure we avoid CT String Failure event. However, this mitigation also should be applied in every CT job regardless of any grade of completion for better execution.
2. Visually inspect the overall CT String prior our 1st run.
3. Ensure to check the end of coil condition when making up connector for the 1st run. Below is the parameter that we need to verify to town prior making up the connector:
    a. Record overall wall thickness from the end of coil up to 3-5ft.
    b. Visually inspect if there is any flat surface / ovality.

    Please proceed cut the coil till the recommended wall thickness is reached. This visual inspection needs to be done for every run.
4. As per current Dimension Bid standard, we need to cut the coil tubing string of approximately 100 ft. The purpose of this method is to:
    a. Shift the fatigue of our CT String
    b. To reduce the possibility of flat surface due to abrasion effect at the whip end of coil.
5. Throughout the CT Operation, we need to lubricate the annulus side of coil tubing string with our friction reducer solution.
6. After every 1000 ft of running, please ensure to;
    a. Perform pull test
    b. Pump at least 2 bbls of friction reducer solution whether through coil or kill port is subject to the tubing head pressure (THP).
7. For additional precaution and by referring to the Angsi A-24L survey deviation below, we need to;
    a. Monitor the weight frequently
    b. Perform additional pull test
    c. Pump additional 2 bbls of friction reducer solution for every time pull test is conducted or every 1000 ft.

Depth Interval (MDDF)	Deviation Range (deg)
542 – 3,653 (EOT)	40 - 70

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Please include all these precautionary steps into each run to ensure we reduce the abrasion effect between our CT String & production tubing.

PRE-OPERATIONAL PROCEDURE

SLICKLINE OPERATION

All depths specified below are in m-MDDF (Drill floor to THF is 16.9-m as per well schematic)

1. Slickline to conduct TCC run to ensure the tubing path is clear from obstruction and record the min ID of the tubing:

Drift ID	***Unit***

2. If fluid level or encountered HUD is found, record it in the following table:

Description	***Depth (m)***
Fluid level	
HUD	

3. Once completed, rig down Slickline unit and handover well to CT operation.

OPERATIONAL PROCEDURE

COILED TUBING OPERATION (LONG STRING) – RUN#1 DEPTH CORRELATION WITH MULTIJET NOZZLE C/W 2.75" FC UNTIL XN-NIPPLE AND PERFORM METHANOL SOAKING

All depths specified below are in m-MDDF (Drill floor to THF is 16.9-m as per well schematic)

Conduct safety meeting with all personnel on location detailing the program, pressure limitations, personnel responsibilities, emergency well control drill, and safety precautions.

1. Prepare 100bbls of Treated Injection Water, TIW as per recipe below:

Treated Injection Water			4,200	gals	100	bbls	Description
Products	Concentration		Volume				
Injection Water	992	gptg	4,166	gals	99.19	bbls	Base Fluid
MESB NE-Surf 200	2	gptg	8	gals	0.19	bbls	Non-Emulsifier Surfactant
ACM Oxyfree 100	2	gptg	8	gals	0.19	bbls	Oxygen Scavenger
ACM H2SClear 200	2	gptg	8	gals	0.19	bbls	CO2 & H2S Corrosion Inhibitor
ACM Bact 200	2	gptg	8	gals	0.19	bbls	Microbiocide

Mixing Instruction:
1. Transfer injection water into mixing tank
2. Add ACM OXYFEE & ACM H2S Clear 200 into the Batch Mixer and circulate the mixture
3. Add NE Surf 200 and ACM BACT 200 into the Batch Mixer and circulate the mixture till homogenous.

Note: The above recipe is for 100bbls of TIW. Please prepare another batch of TIW once needed.

2. Prepare 50bbls of D801 Cleanout Gel as per recipe below:

D801 Cleanout Gel				50	BBL	*Description*
Seq.	*Product*	*Concentration*		*Volume*		
1	Injection Water	992	gptg	2,083	gal	Base Fluid
2	D801 Gel	40.5	pptg	85	lbs	Gelling Agent

Mixing Instruction:
1. Prepare fresh water in the mixing tank.
2. Add D801 Gel into the tank and circulate the mixture until homogenous.

Note: The above recipe is for 50bbls of D801 Gel. Please prepare another batch of D801Gel once needed.

3. Rig up coiled tubing unit and surface line on Angsi-A platform as per Site Visit Report:
   - 3.1. Review JHA and risk assessment with all personnel involve in the rig up operation. Please send a copy of JHA to Engineer in Charge.
   - 3.2. Lift up coiled tubing unit using crane and spot on platform.
   - 3.3. Rig up Coiled Tubing package and surface treating line.
   - 3.4. Rig up 2" kill line to BOP kill port.
   - 3.5. Rig up 2" flexible hose from pumping tee.
   - 3.6. Pig coil tubing with treated sea water to ensure no debris is inside coil. **Record coil tubing volume in treatment report.**
   - 3.7. **Ensure pump volume, pump rate, N2 rate, circulating pressure, well head pressure, weight is synchronise with OrionNet**

3.8. Make up the **CT End Connector**.

3.9. Install the Pull and Pressure Test Sub.

3.10. Perform Pull Test on the CT End Connector **to 15,000 lbf at least** and record this in OrionNet.

Note: Do not perform pull test more than 80% coil limit. Consult with town if require.

3.11. Perform Pressure Test on CT End Connector. Pumping treated sea water through the coiled tubing, apply low pressure test of **300 psi for 5 minutes** and high-pressure test of **5,000 psi for 15 minutes** after stabilization. Record the pressure test.

3.11.1. For low pressure:

Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 270 psi) over 5-minutes test interval after the pressure stabilizes.

3.11.2. For high pressure:

Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 4,500 psi) over the 15- minutes test interval after the pressure stabilizes.

4. Make up 2.125" MultiJet Nozzle tool as per **BHA#1: 2.125" MultiJet Nozzle** in **Appendix 1**.

5. Perform function test of the MultiJet Nozzle to determine at which pump rate and pressure of the tool. Record the data in the table below, do not exceed 5,000psi.

Flow rates (bpm)	Pressure (psi)	Remark
0.3		
0.5		
0.6		
0.7		
0.8		
0.9		
1.0		
1.1		
1.2		
1.3		

6. Pick up coiled tubing and tag the stripper with the BHA.

7. Make up the Injector Head and Stripper to the stack up.

8. Coiled tubing stack up pressure test against Wellhead Swab valve. Pumping treated sea water through the coiled tubing, apply low pressure test of **300 psi for 5 minutes** and high-pressure test of **3,000 psi for 15 minutes** after stabilization. Record the pressure test. Record test on a chart. Upon successful pressure test, bleed off pressure via Pump-In Sub.

8.1. For low pressure:

Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 270 psi) over 5-minutes test interval after the pressure stabilizes.

8.2. For high pressure:

Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 4,500 psi) over the 15- minutes test interval after the pressure stabilizes.

9. Pressure test the BHA Check Valve with **3,000 psi** in the coiled tubing stack up, bleed off the stack up pressure to **1,500 psi** via pump-in sub; and bleed off pressure in the coiled tubing to zero (0) psi via reel manifold.

9.1. Acceptance criteria: **Pressure drop is less than 10% (above 1,350 psi) over the 15- minute test interval after the pressure stabilizes.** Observe for any pressure changes in the stack up. If the

BHA check valve is not holding, proceed to replace the MHA; do not run-in hole with leaking check valve; repeat steps 8.2 and 9.

10. Upon successful test, bleed off the pressure in the coiled tubing stack up to zero through the pump-in sub.
11. Zero both depth counters at reference point.
12. Confirm all wellhead and BOP valves are in open position via physical check.
    12.1. Prior to opening the wellhead valve pressure up above master valves to a pressure equal to the expected shut-in wellhead pressure.
    12.2. Count wellhead valves turns while opening and record it the treatment report for reference in future.
    12.3. Manipulate surface valve to the following position:

Valve	Position
Reel Manifold	OPEN
Flow Cross Return Valve (Cetco lines)	OPEN
Wing Valve	CLOSE

    12.4. Record initial SITHP of short string and long string and PCP of well A-24L.
13. Start running in hole coil tubing to **3,383 m MDDF / 11,099 ft MDDF (10 m above EOT)** while pumping **Treated Injection Water** at minimum rate permissible.
    13.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix III.
    13.2. Conduct pull test as per for every 300m (1,000ft), use CT Fatigue graph as reference. Ensure the CT Fatigue graph is available at location before RIH. Record RIH, Hanging and POOH weight in daily operation report and manual job log at all time.
    13.3. Maximum coil speed running in hole is **30-50 ft/min.**
    13.4. Slow down coil speed to **10 ft/min**, 50 ft before and after passing through completion accessories.
    13.5. Closely observe weight indicator in control cabin while running in hole.
    13.6. Observe return all the times.
    13.7. Regularly inform WSS on job status at all times.
    13.8. Do not exceed operating safety limits **5,000 psi.**
    13.9. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
    13.10. At all time, while run-in hole, the injector torque control shall be set at the minimum pressure required to move the Coiled Tubing at specified speed.
14. Once CT reach **3,383 m MDDF / 11,099 ft MDDF (10 m above EOT),** conduct pull test of 10m/30ft with pumping rate 0.3BPM and record the pulling weight both static and dynamic (IMPORTANT).

Depth, ft	***RIH weight, lbf***	***Static weight, lbf***	***Pick up weight, lbf***

15. Continue RIH until XN-Nipple at 3,393 m / 11,132 ft MDDF.
16. Once CT reach and tag XN-Nipple depth at 3,393 m / 11,132 ft MDDF, proceed to pick up CT to 10 m above XN-Nipple**,** and continue to RIH to re- tag XN-Nipple to verify the depth. Repeat this step twice prior to flag CT on surface (Flag #1).

Flag Number	***Colour***
Flag#1	

17. With the coiled tubing station at the XN-Nipple (Flag #1), proceed to mix the following **TFW** solution for Injectivity Test.

18. Prepare 273 bbls (1.5x completion volume) of **Treated Fresh Water, TFW** as per recipe below:

Treated Fresh Water			4,200	gals	100	bbls	Description
Products	Concentration		Volume				
Fresh Water	959	gptg	4,029	gals	95.93	bbls	Base Fluid
MESB NE-Surf 200	2	gptg	8	gals	0.19	bbls	Non-Emulsifier
Ammonium Chloride	417	pptg	1,751	lbs			Clay Stabilizer
ACM Oxyfree 100	2	gptg	8	gals	0.19	bbls	Oxygen Scavenger
ACM H2SClear 200	2	gptg	8	gals	0.19	bbls	CO_2 & H_2S Corrosion Inhibitor
ACM Bact 200	2	gptg	8	gals	0.19	bbls	Microbiocide

Mixing Instruction:

1. Fill up tank with fresh water
2. Add additives as per above sequence
3. Agitate until the mixture is homogenous

Note: The above recipe is for 100bbls of TFW. Please prepare another batch of TFW once needed.

19. Prior start pumping activity once completed mixing, record shut in tubing head pressure (THP) and casing head pressure (CHP). Include in daily report.

THP (psi)	CHP (psi)

20. Bleed off tubing and casing pressure to 0 psi or to minimum as possible.
21. Once complete above step, proceed to fill up the completion volume with 273 bbls (1.5x completion volume) TFW or till steady return is observe on surface without any Nitrogen injection, whichever comes first.
    21.1. Do not exceed 5,000 psi CT Circulation pressure or 1,300 psi THP/WHP during pumping activity. Whichever comes first.
    21.2. If THP/WHP exceed 1,300 psi during pumping, stop pump and bleed off pressure prior re-attempt the Injectivity Test.
    21.3. Consult town in the event the pumping pressure still above 1,300 psi after re-attempt.
    21.4. Ensure that one personnel are on standby at fluid storage tank during pumping to monitor fluid level.
    21.5. While filling up tubing, record THP and CHP as per table below. Include the following table in daily report.

Time (min)	Pump Pressure (psi)	Volume (bbl)	THP (psi)	CHP (psi)	Remark

22. Proceed with pump TFW to fill up completion volume (**273 bbls**) prior injectivity test as per below table:

Pumping Schedule to Fill up Completion Volume for Injectivity Test						
Stage	Description	Fluid	Vol (bbl)	Pump Rates (bpm)	Remarks	MASTP (psi)
1	**Fill-up Completion Volume**	**TFW**	273 bbls or till return is observed on	0.5-1.0	273 bbls is calculated based on	1300

			surface without N2 Injection		1.5x completion volume	

23. After well is full with TFW, manipulate surface valves as following position prior commence with Injectivity test.

Valve	Position
Reel Manifold	OPEN
Flow Cross Return Valve (Cetco lines)	CLOSE
Wing Valve	CLOSE

24. Begin injectivity test via coiled tubing as per table below:

Rate (bpm)	Pumping Pressure (psi)	Time (min)	Volume (bbls)	THP/WHP LS (psi)	THP SS (psi)	CHP (psi)
0.30						
0.50						
0.70						
0.90						
1.00						
1.10						
1.20						
1.30						
1.40						

24.1. Ensure PCSB Representative is available and witness the injectivity test.

24.2. Sustain each pumping rate for 5 minutes after pressure stabilises.

24.3. DO NOT exceed MASP/WHP of 1,300 psi.

24.4. Fill up table and include in daily report. Report the results of injectivity test to PCSB and DB EIC.

24.5. Minimum injectivity require for this treatment is 0.3 bpm to 0.5 bpm.

25. After completed injectivity test, manipulate wellhead valves as below:

Valve	Position
Reel Manifold	OPEN
Flow Cross Return Valve (Cetco lines)	OPEN
Wing Valve	CLOSE

26. Continue pump TFW with idle rate and monitor return while preparing all required fluid.

27. Report the injectivity test result to EIC and WSS.

28. Before proceed with stimulation operation that involve flammable liquid, ensure all crew understand with below guideline:

28.1. A pre job safety meeting should be held prior operation to ensure all crew and relevant parties familiar with the Handling, Spillage, Fire-Fighting and MSDS.

28.2. Before mixing activity, ensure to have a proper mixing plan and it is advisable to mixing during the night time. Locate the tank, batch mixer and pumping unit away from hot condition and near to water source.

28.3. When handling methanol (flammable liquid), all equipment (tank, pump, batch mixer, wilden pump, basket containing methanol drum and etc) that involved during mixing and pumping activity must have a grounding cable and clamp it on platform structure. Ensure there is a good metal to metal contact.

28.4. Whenever flammable liquids are to be taken onboard the storage tanks, the system must be checked for leaks before starting engines.

28.5. To minimize risks, the volume of flammable liquids should not exceed 70% of the tank volume. Rough weather must be taken into consideration.

28.6. The pump rate must be at low rate to reduce generation of heat from friction of plunger during pumping activity.

28.7. Flammable liquid under pressure should not be bled off / released to the tank or drainage through a partially opened plug valve.

28.8. The sight glass level gauge of the tank must be visible to prevent occurrence of spark due to loss prime because of the tank has empty (no fluid to pump).

28.9. Barricade the area and ensure all personnel that involved during operation did not bring any spark producing device or electrical equipment.

28.10. Ensure there is running water on the tank, plunger of the pump and wilden pump during operation. Ensure fire extinguisher is available at this area.

28.11. Safety officer / firewatcher must be available at all time during operation and ensure all crew involved during operation comply and aware of the procedure.

29. Once obtain approval from DB EIC and PCSB EIC to proceed with the stimulation operation, prepare main treatment fluid as per below recipe:

Seq.	2% Brine + 30% Methanol				4,200	gals	100	bbls	Description
	Products	Concentration		Volume					
1	Fresh Water	693	gptg	2,911	gals	69.31	bbls		Base Fluid
2	Pottasium Chloride	167	pptg	701	lbs				Clay Stabilizer
3	Methanol	300	gptg	1,260	gals	30.00	bbls		Methanol

30. Once all the treatment fluid are prepared, manipulate wellhead valves as below:

Valve	Position
Reel Manifold	OPEN
Flow Cross Return Valve (Cetco lines)	CLOSE
Wing Valve	CLOSE

31. After completed fluid preparation, while CT station at XN Nipple at 3,393 m / 11,132 ft MDDF with reference of Flag#1**,** proceed with pumping main treatment as per below pumping schedule:

31.1. Do not exceed MASTP/WHP during pumping operation.

31.2. In the event WHP pressure exceed the limit during pumping operation, stop pump and bleed off the tubing pressure to minimum prior continue with pumping operation.

31.3. Consult town if the pumping pressure still exceeding MASTP after bleed off operation.

Pumping Schedule for I-100 Zone						
Stage	Description	Fluid	Vol (bbl)	Pump Rates (bpm)	Remarks	MASTP (psi)
1	**Methanol Soaking**	Methanol	95	1.0	For condensate banking	1,300
2	**Displacement**	TIW	85	1.0	To spot Methanol at wellbore and penetration design	1,300
3	**Displacement**	TIW	25	1.0	To displace coil volume	1,300
Shut in well and soak for 12 hours						

- **Max WHP is 1,300 psi throughout pumping sequence.**
- **Actual CT string volume will be confirmed during rig up.**
- **Maintain pumping rate throughout the pumping stage. To compare injectivity index pre and post treatment.**

32. Record the following parameters while pumping via CT. Include the following table in daily report.

Time (min)	Pump Pressure (psi)	Volume (bbl)	THP (psi)	CHP (psi)	Remark

33. Once completed pumping, POOH CT to surface and soak the treatment for 12 hours.
34. POOH CT to surface without pumping. Ensure continuous return on surface is observe.
    34.1. Maximum coil speed while POOH is 50ft/min.
    34.2. Slow down coil speed to 10ft/min 50ft before and after passing through completion accessories.
35. Once CT on surface, close well and bleed off pressure in coil and stack up. Change to Unloading BHA and proceed to Run#2 to perform N2 Unloading in next run.

COILED TUBING OPERATION (LONG STRING) – RUN #2 NITROGEN UNLOADING

All depths specified below are in m-MDDF (Drill floor to THF is 16.9-m as per well schematic)

Conduct safety meeting with all personnel on location detailing the program, pressure limitations, personnel responsibilities, emergency well control drill, and safety precautions.

36. Make up 1.69” Upward Jetting Nozzle tool as per **BHA#2: 1.69” Upward Jetting Nozzle** in **Appendix I**.

37. Ensure LN2 tank on the platform is in full condition. If LN2 tank is in low condition, consider to transfer or swap the empty tank with full tank that standby on the vessel.

38. Repeat step 6 till 12 in Run#1 prior opening the well.

39. Start running in hole coil tubing to first circulation point depth at **2,895m MDDF** while perform break circulation with 0.3 BPM of TIW for every 1,000 ft. First circulation point start at **2,895 m / 9,500 ft MDDF** to clear out fluid column inside tubing until across I-100 Perforation depth at **3,653 m / 11,985 ft MDDF** (maximum circulation depth).

    39.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix III.

    39.2. Conduct pull test as per for every 300 m / 1,000 ft use CT Fatigue graph as reference. Ensure the CT Fatigue graph is available at location before RIH. Record RIH, Hanging and POOH weight in daily operation report and manual job log at all time.

    39.3. Perform break circulation for every 1,000 ft.

    39.4. Maximum coil speed running in hole is **30-50 ft/min.**

    39.5. Slow down coil speed to **10 ft/min**, 50 ft before and after passing through completion accessories.

    39.6. Closely observe weight indicator in control cabin while running in hole.

    39.7. Observe return all the times. If observed fluid return at surface, station CT at depth to unload all liquid until gas return at surface before proceed to RIH 300 m /1,000 ft deeper.

    39.8. Regularly inform WSS on job status at all times.

    39.9. Do not exceed operating safety limits **5,000 psi.**

    39.10. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.

    39.11. At all time, while run-in hole, the injector torque control shall be set at the minimum pressure required to move the Coiled Tubing at specified speed.

40. At **2,885 m MDDF (10m before first circulation depth)**, stop coil and conduct pull test of 10m/30ft and record the pulling weight both static and dynamic (IMPORTANT).

Depth, ft	***RIH weight, lbf***	***Static weight, lbf***	***Pick up weight, lbf***

41. Upon completion pull test, continue RIH until **2,895 m / 9,500 ft MDDF (first circulation point depth)** and start pumping nitrogen with N2 rate 500 scf/min for 30 minutes while monitoring the returns on surface.

    41.1. If fluid is observed at surface at a good flow rate, continue lifting until all fluid is recovered.

    41.2. Constantly monitor & record the return from the well and THP. Periodically take fluid sample and verify the salinity.

    41.3. If there is no fluid return at surface, continue pumping nitrogen and RIH to the next depth as per table below:

Client PCSB
Well A24L
Field Angsi
Job N2 Unloading
Date 27 November, 2022

DIMENSION BID

No.	Stage	N2 Rate	Total N2	Duration	Coiled Tubing					
		SCFM	SCF	Minute	ft/min	From (ft)	From (m)	To (ft)	To (m)	Total Footage (ft)
1	RIH	0	0	35	30	0	0	1050	320	1050
2	Pull Test	0	0	3	20	1050	320	1000	305	50
3	RIH	0	0	35	30	1000	305	2050	625	1050
4	Pull Test	0	0	3	20	2050	625	2000	610	50
5	RIH	0	0	35	30	2000	610	3050	930	1050
6	Pull Test	0	0	3	20	3050	930	3000	914	50
7	RIH	0	0	35	30	3000	914	4050	1234	1050
8	Pull Test	0	0	3	20	4050	1234	4000	1219	50
9	RIH	0	0	35	30	4000	1219	5050	1539	1050
10	Pull Test	0	0	3	20	5050	1539	5000	1524	50
11	RIH	0	0	35	30	5000	1524	6050	1844	1050
12	Pull Test	0	0	3	20	6050	1844	6000	1829	50
13	RIH	0	0	35	30	6000	1829	7050	2149	1050
14	Pull Test	0	0	3	20	7050	2149	7000	2133	50
15	RIH	0	0	35	30	7000	2133	8050	2454	1050
16	Pull Test	0	0	3	20	8050	2454	8000	2438	50
17	RIH	0	0	35	30	8000	2438	9050	2758	1050
18	Pull Test	0	0	3	20	9050	2758	9000	2743	50
19	RIH	0	0	18	30	9000	2743	9550	2911	550
20	Pull test	0	0	3	20	9550	2911	9500	2895	50
21	**Circulation**	500	15000	30	0	**9500**	2895	**9500**	2895	0
22	RIH	500	17500	35	30	9500	2895	10550	3215	1050
23	Pull test	500	1250	3	20	10550	3215	10500	3200	50
24	**Circulation**	500	15000	30	0	**10500**	3200	**10500**	3200	0
25	RIH	500	833	2	30	10500	3200	10550	3215	50
26	Pull test	500	1250	3	20	10550	3215	10500	3200	50
27	**Circulation**	500	15000	30	0	**10500**	3200	**10500**	3200	0
28	RIH	500	17500	35	30	10500	3200	11550	3520	1050
29	Pull test	500	1250	3	20	11550	3520	11500	3505	50
30	**Circulation**	500	15000	30	0	**11500**	3505	**11500**	3505	0
31	RIH	500	8083	16	30	11500	3505	11985	3653	485
32	**Circulation (EOT)**	500	15000	30	0	**11985**	3653	**11985**	3653	0
33	POOH	300	119850	400	30	11985	3653	0	0	11985
		Total N2, SCF	**242,517**	**18 Hours**						
		Total N2, Gal	**2,604**							

****Circulation*: First circulation point depth***

****The unloading time for each specific depth can subject to change depending on return condition***

**** The volume of required N2 above not including cooling down and 10% losses***

42. Continue RIH until **3,653 m MDDF / 11,985 ft MDDF** (maximum circulation depth).

    Note:

    - The reference depth (11,985 ft MDDF) can be changed based on decision from town.
    - At 11,985 ft MDDF, total fluid column to be displaced is 104 bbls. Total fluid pumped is 307.5 bbls (1.5X Fluid Pumped in previous run). Total volume to unload is 411 bbls (fluid column + fluid pumped).
    - Ensure flowback crew to divert liquid return into surge tank to calculate volume displace recovered at surface.
    - If N2 is found excessive in return, reduce N2 rate into 300 scfm and observe return. If no fluid observed at return, try to RIH deeper, adjust N2 rate accordingly, and consult with town before proceed further.

43. Stop pumping N2 once get continuous gas return on surface.

44. In the event, coil experience high surface weight reading while RIH and Pull test, proceed to mix Metal to Metal friction reducer as per the following recipe and pump at 1.0 bpm through coil.

Friction Reducer Solution (3% Friction Reducer)				**10**	***BBL***	***Description***
Seq.	***Product***	***Concentration***		***Volume***		
1	Injection Water	968	gptg	406	gal	Base Fluid
2	H2S Clear	2	gptg	1	gal	CO2 & H2S Corrosion Inhibitor
2	IM Lube	30	gptg	13	gal	Friction Reducer

Mixing Instruction:

3. Prepare injection water in the mixing tank.
4. Add H2S Clear and IM Lube into the tank and circulate the mixture at least 10 minutes until homogenous.

45. Once observe continuous gas return at surface for at least 30 minutes at depth 11,985 ft MDDF, POOH CT to surface.

    45.1. Pump N2 at minimum permissible rate while POOH. Do not exceed 4,500 psi pumping pressure.

    45.2. Maximum coil speed while POOH is 50ft/min.

    45.3. Slow down coil speed to 10ft/min 50ft before and after passing through completion accessories.

    45.4. Do not exceed CT Operating Limit.

46. Once CT on surface, close well, bleed off pressure in coil and stack up and handover well to production.

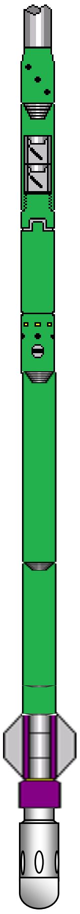
APPENDIX I – BOTTOM HOLE ASSEMBLY SCHEMATIC

BHA #1: 2.125” MULTIJET NOZZLE C/W 2.75 FLUTED CENTRALIZER

DIMENSION BID

BHA DIAGRAM #1 - 2.125" Multijet Nozzle c/w 2.75" FC

Client	**Petronas Carigali**	**Well**	**A-24L**
Field	**Angsi Andra**	**Min Restriction**	**2.69"**
Job Type	**Unloading**	**BHP**	
Job No.		**BHT**	

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	**Internal Dimple Connector**	1.5" CT	1.0" AMMT PIN		1.690	0.6	0.6
	MHA Disconnect drop ball 5/8" Shear pressure 5,456 psi Circulating drop ball 1/2" Shear pressure 2,520 psi Burst Disc 5000 psi	1.0" AMMT BOX	1.0" AMMT PIN		1.690	2.3	2.9
	5 FT Straight Bar	1.0" AMMT BOX	1.0" AMMT PIN		1.690	5.0	7.9
	3 FT Straight Bar	1.0" AMMT BOX	1.0" AMMT PIN		1.690	3.0	10.9
	Crossover	1.0" AMMT BOX	1.5" AMMT PIN		2.125	0.50	11.4
	Fluted Centralizer	1.5" AMMT BOX	1.5" AMMT PIN		2.750	1.0	12.40
	Multijet Nozzle	1.5" AMMT BOX			2.125	0.60	13.0

BHA LENGTH	**13.00**
MAXIMUM OD	**2.75**
MINIMUM ID	

Prepared by:	Muhd Ameerul Zaeem
Review by:	
Revision:	
Date:	

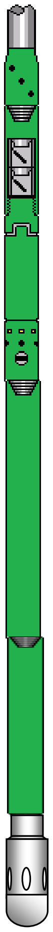
ADDITIONAL INFORMATION:

BHA #2: 1.69" UPWARD JETTING NOZZLE

DIMENSION BID

BHA DIAGRAM #2 - 1.69" Upward Jetting Nozzle

Client	Petronas Carigali		Well	A-24L
Field	Angsi Andra		Min Restriction	2.69"
Job Type	Unloading		BHP	
Job No.			BHT	

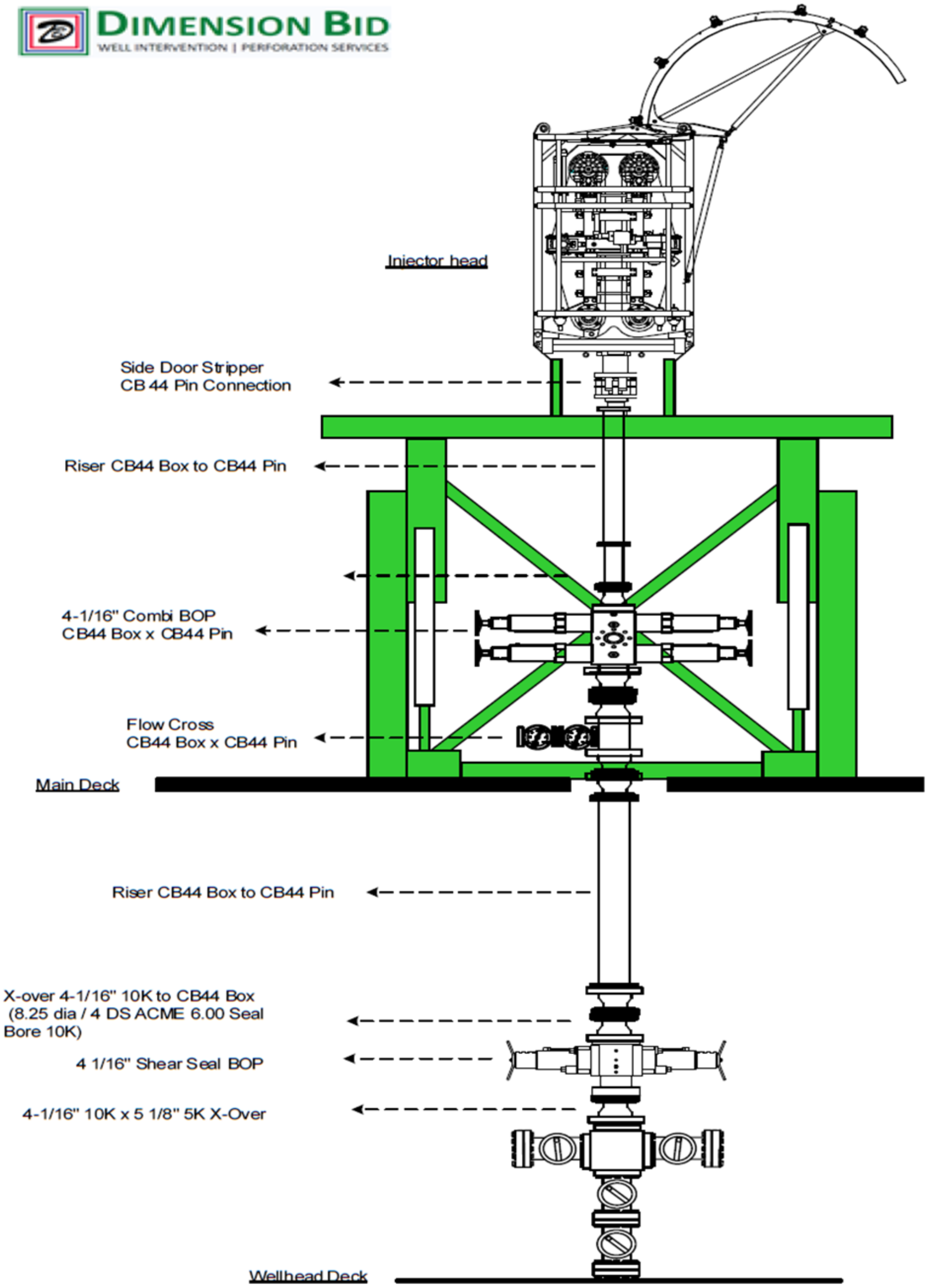
BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	**Internal Dimple Connector**	1.5" CT	1.0" AMMT PIN		1.690	0.6	0.6
	MHA Disconnect drop ball 5/8" Shear pressure 5,456 psi Circulating drop ball 1/2" Shear pressure 2,520 psi Burst Disc 5000 psi	1.0" AMMT BOX	1.0" AMMT PIN		1.690	2.3	2.9
	5 FT Straight Bar	1.0" AMMT BOX	1.0" AMMT PIN		1.690	5.0	7.9
	3 FT Straight Bar	1.0" AMMT BOX	1.0" AMMT PIN		1.690	3.0	10.9
	45° Upward Jetting Nozzle	1.0" AMMT BOX			1.690	0.60	11.5

BHA LENGTH	11.50
MAXIMUM OD	1.69
MINIMUM ID	

Prepared by:	Muhd Ameerul Zaeem
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

APPENDIX II – COILED TUBING STACK UP



APPENDIX III – ENGINEERING ANALYSIS

Summary Tubing Force Analysis

- Calculation at depth 3,392 m MDDF

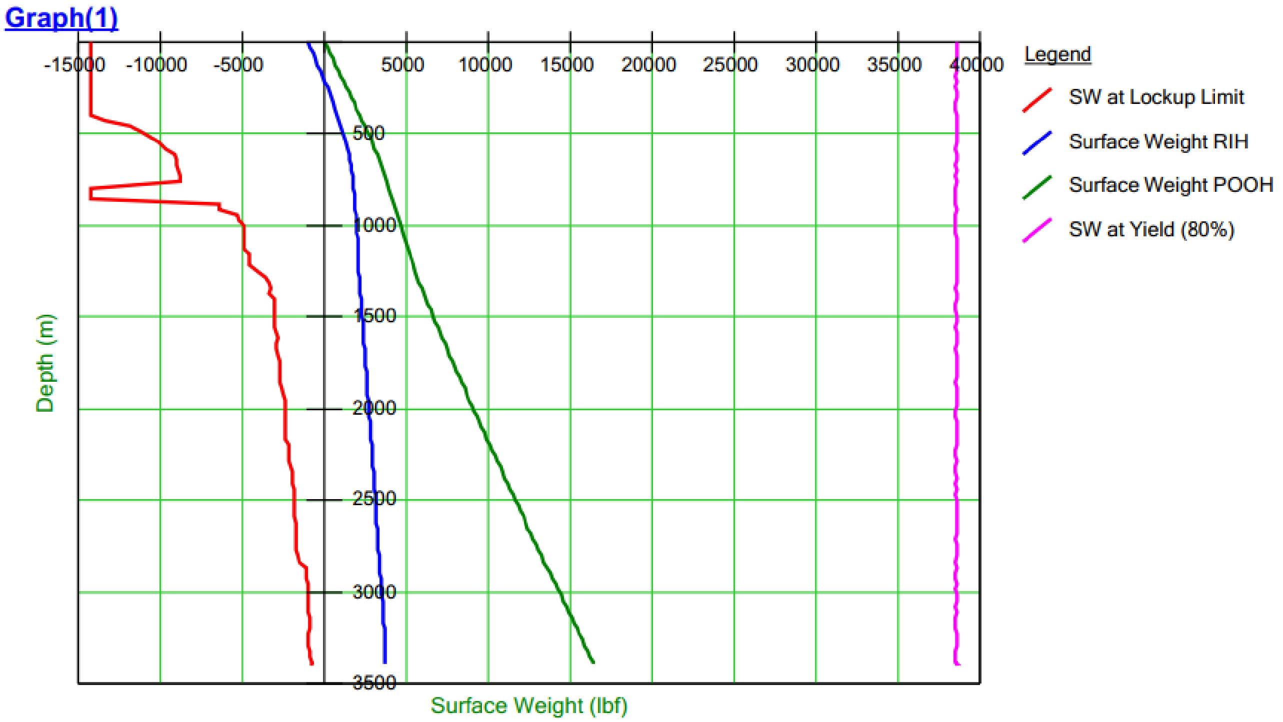
Parameter	Maximum set down weight (lbf)	Surface weight reading (lbf)	Maximum pick up weight (lbf)	Surface weight reading (lbf)
Multijet Nozzle with 0.3 bpm	-2461	-696	13323	38534
Multijet Nozzle with 1.3 bpm	-2374	-1261	12686	36819
Multijet Nozzle with Nitrified (0.9 bpm + 400 scf/min)	-2677	-1680	13419	37344

- Calculation at depth 3,653 m MDDF

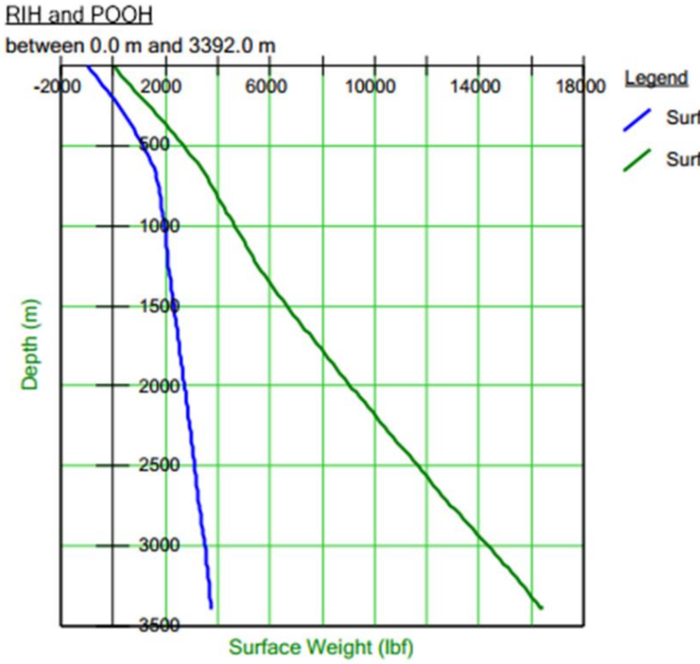
Parameter	Maximum set down weight (lbf)	Surface weight reading (lbf)	Maximum pick up weight (lbf)	Surface weight reading (lbf)
Upward Nozzle with 300 scf/min	-2576	512	10708	38552
Upward Nozzle with 500 scf/min	-2569	415	10745	38517

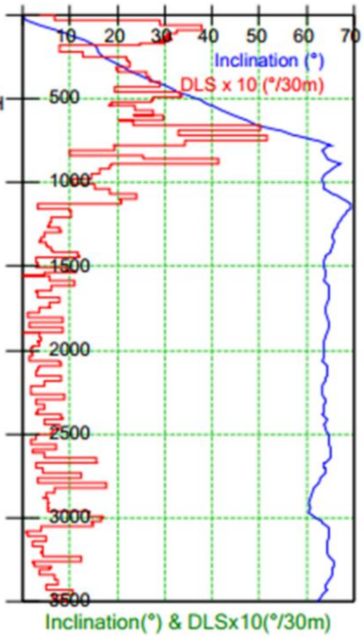
TUBING FORCE ANALYSIS (Orpheus Modelling)

- Run #1 (Multijet Nozzle) with **0.3 BPM of TIW**



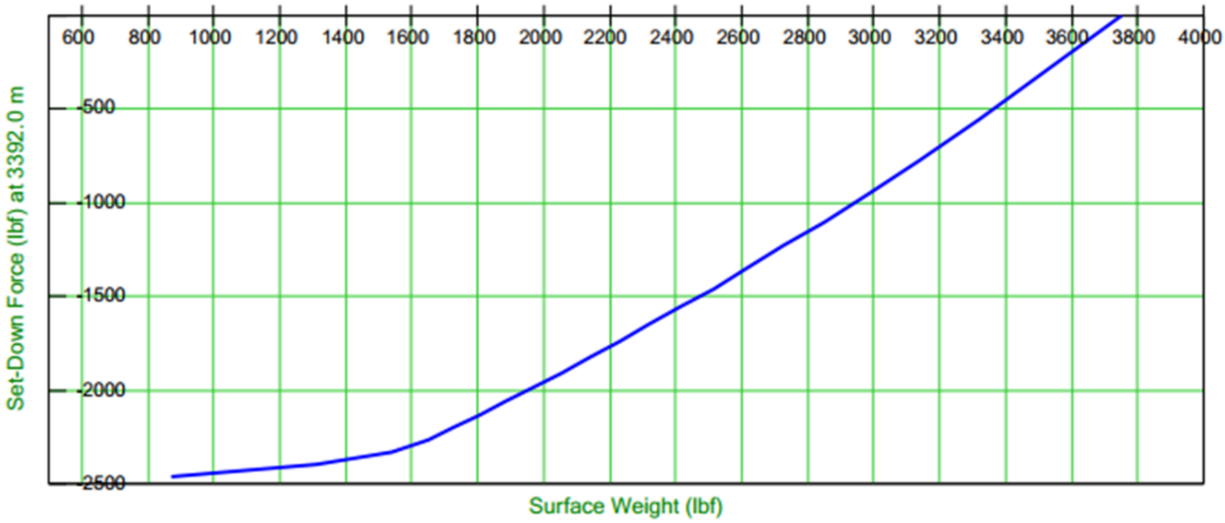
RIH & POOH WEIGHT





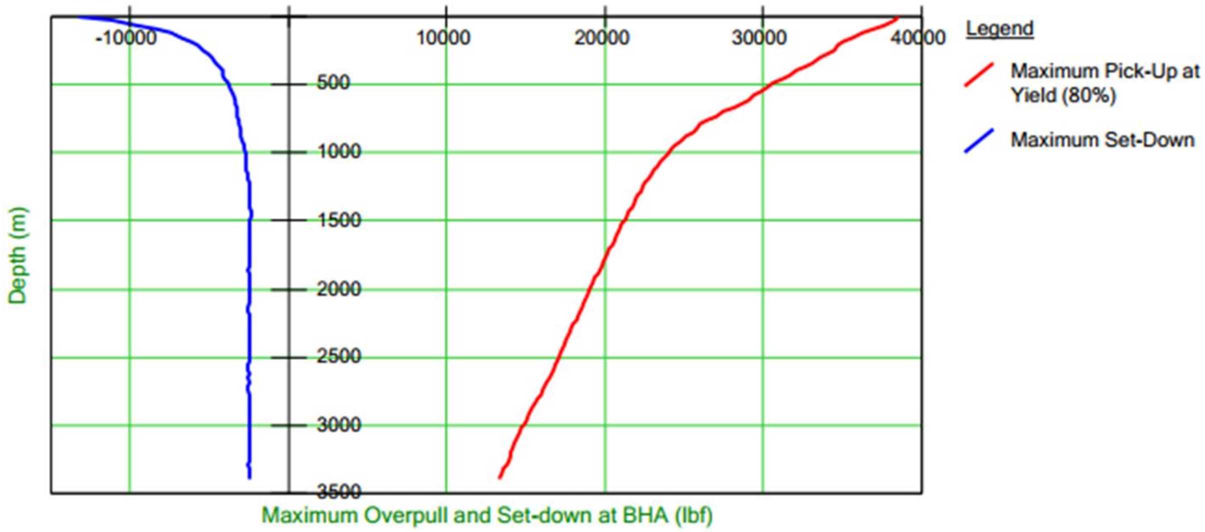
MAXIMUM STRING SET DOWN LIMIT

MD3 The available set-down force at 3392.0 m is -2461 lbf at the end of the string.
The weight indicator reading will be -696 lbf on surface.
The minimum available set-down force is -2403 lbf at 1432.6 m.



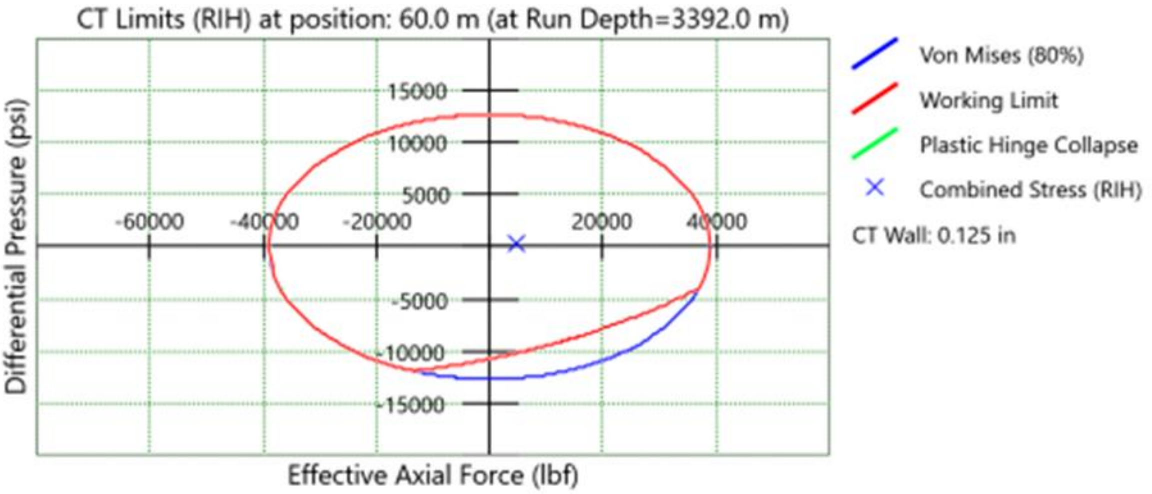
MAXIMUM STRING PICK UP LIMIT

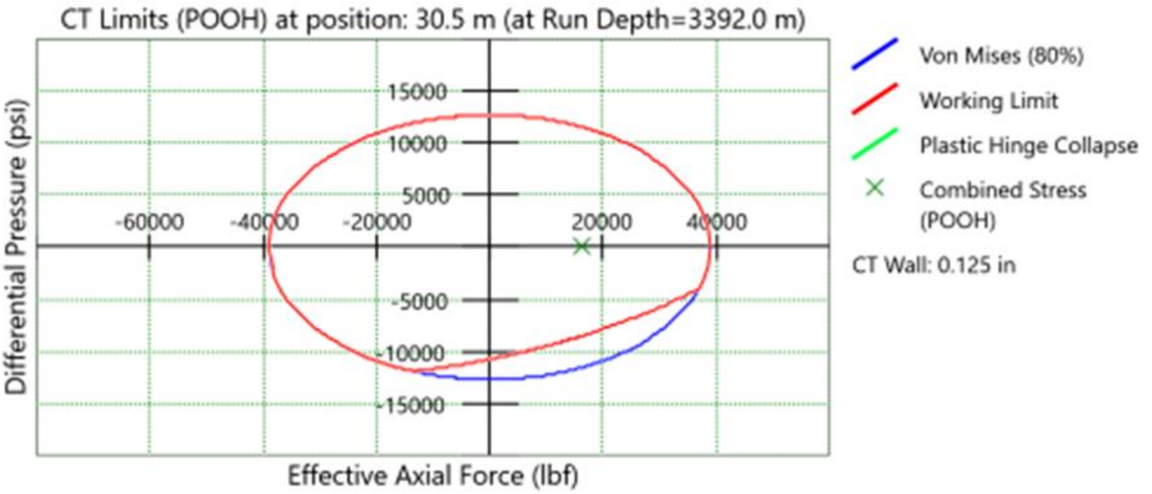
MD1 The available pick-up at 3392.0 m based on 80% of yield strength is 13323 lbf.
The weight indicator reading will then be 38534 lbf.



STRING LIMIT

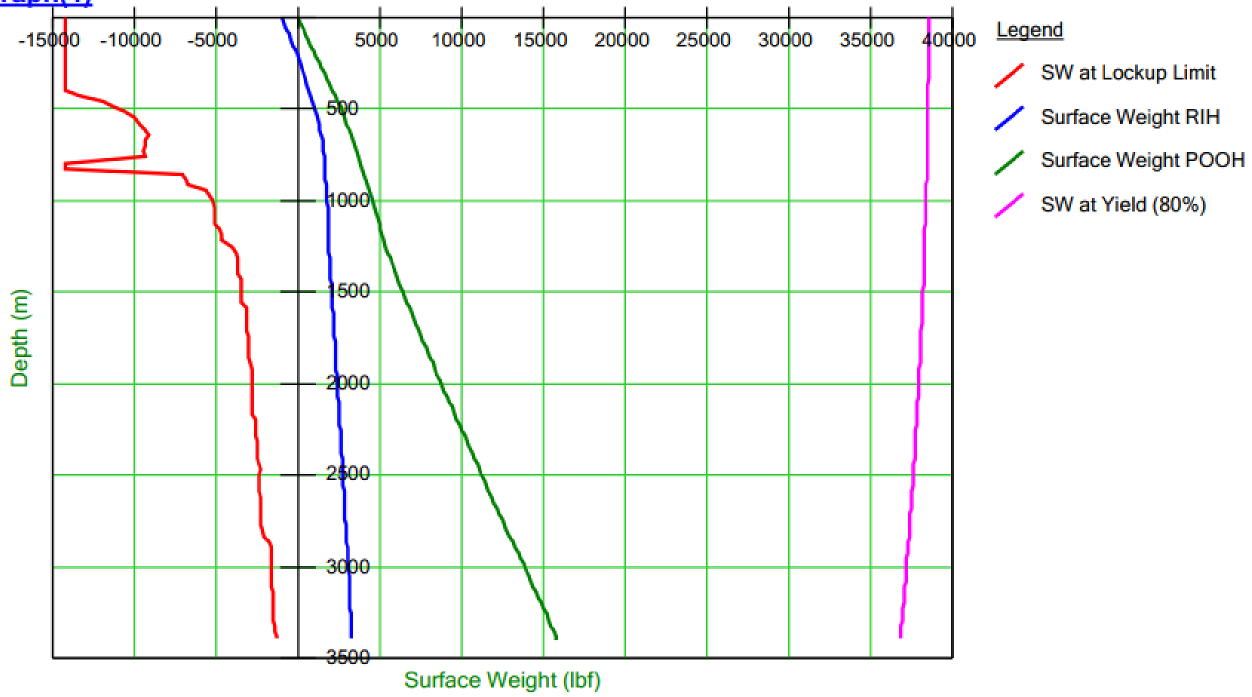
CT Limits



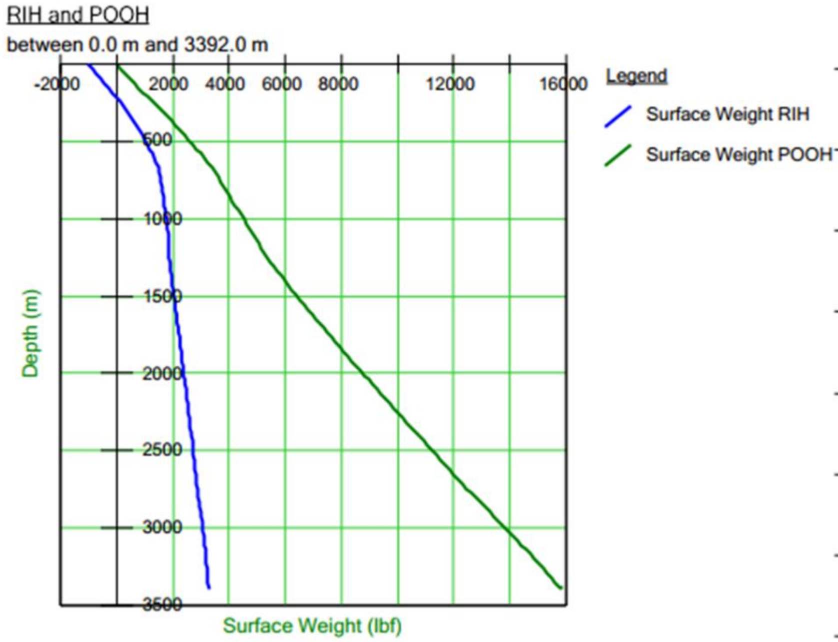


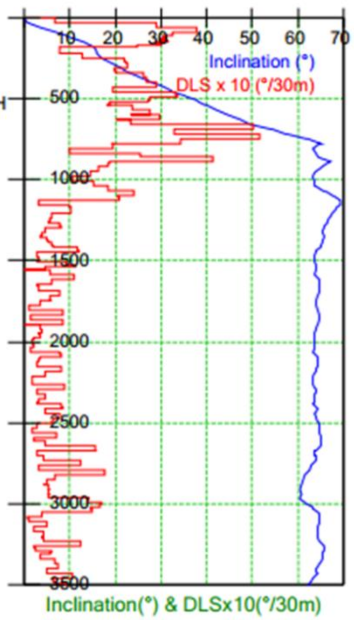
- Run #1 (Multijet Nozzle) with **1.3 BPM of TIW**

Graph(1)



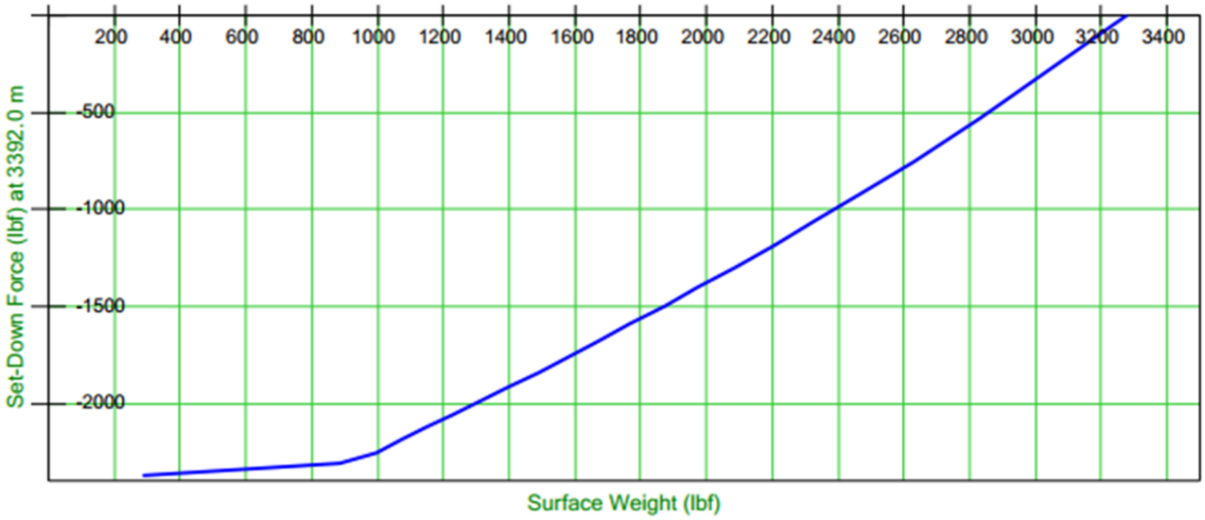
RIH & POOH WEIGHT





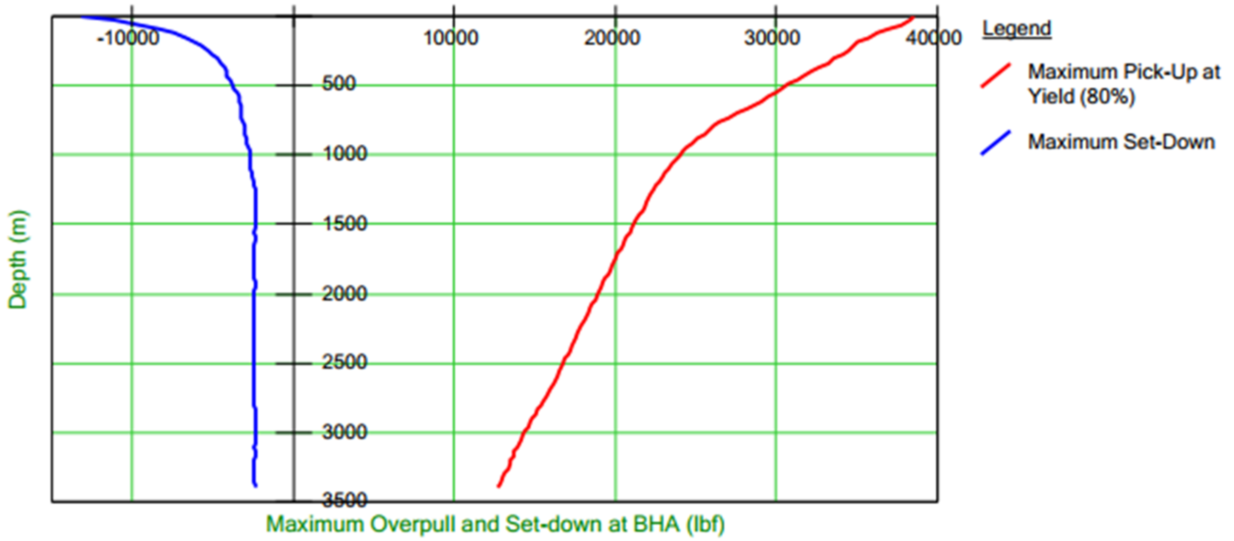
MAXIMUM STRING SET DOWN LIMIT

MD3 The available set-down force at 3392.0 m is -2374 lbf at the end of the string.
The weight indicator reading will be -1261 lbf on surface.
The minimum available set-down force is -2351 lbf at 1463.0 m.



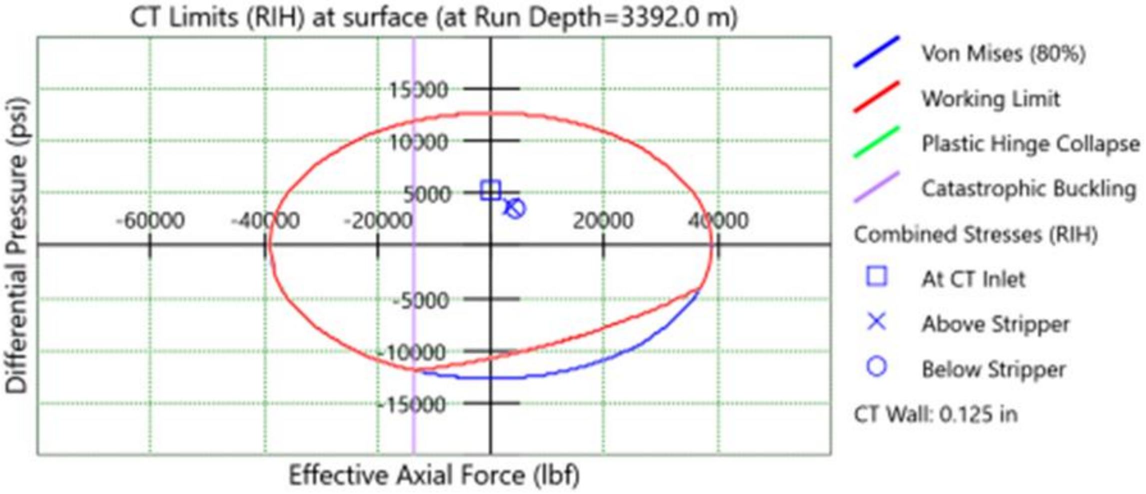
MAXIMUM STRING PICK UP LIMIT

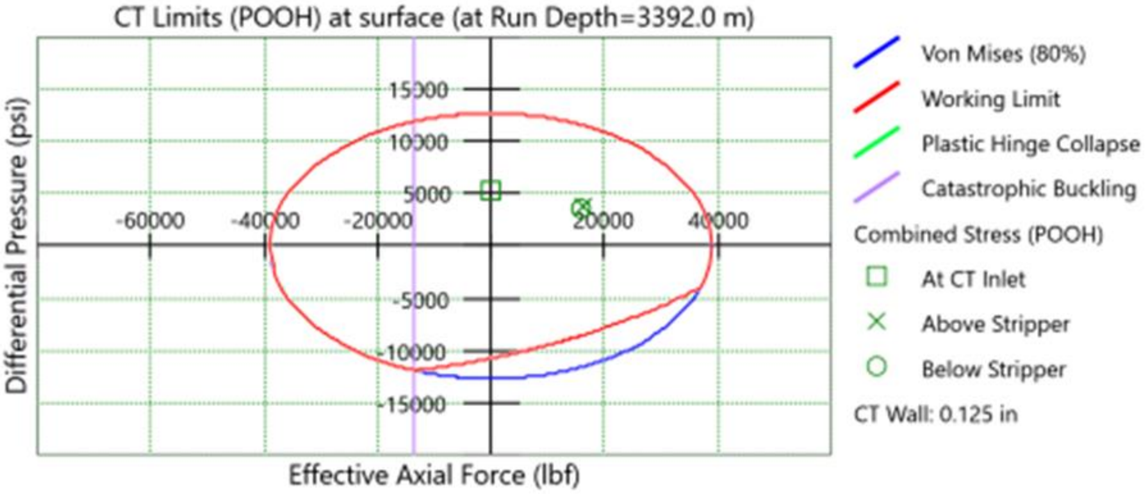
MD1 The available pick-up at 3392.0 m based on 80% of yield strength is 12686 lbf.
The weight indicator reading will then be 36819 lbf.



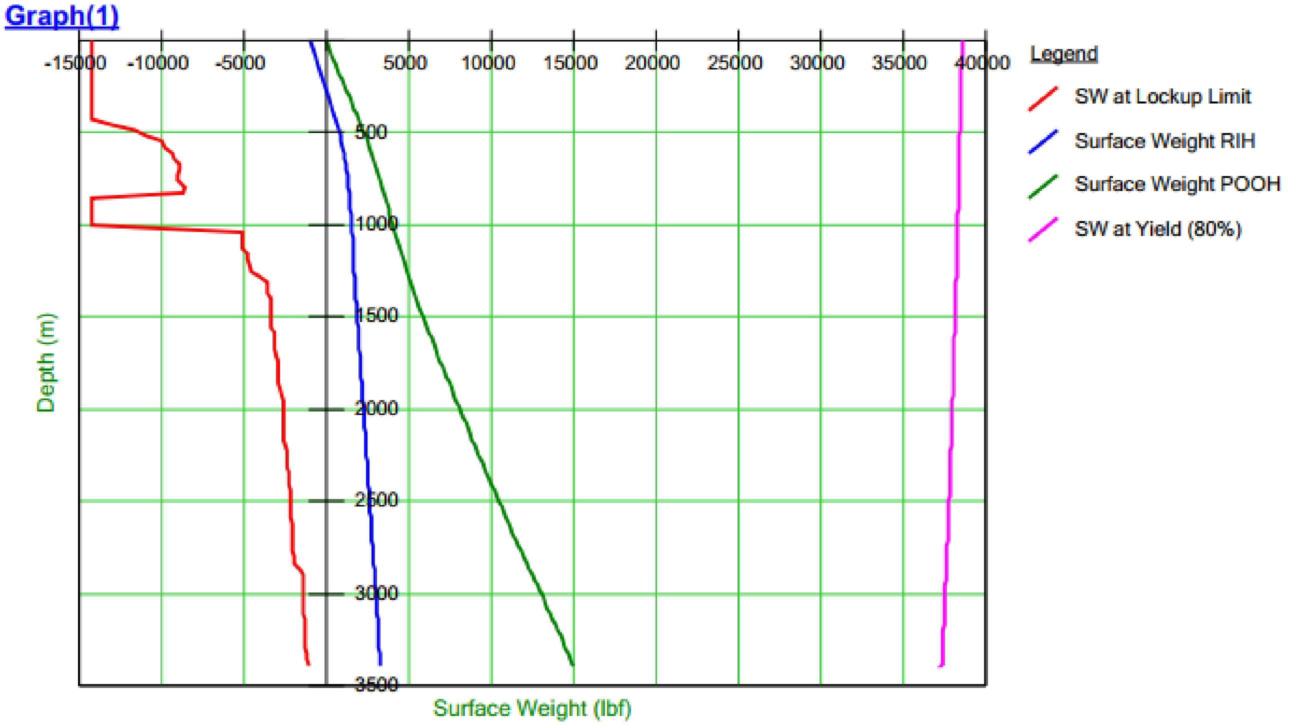
STRING LIMIT

CT Limits

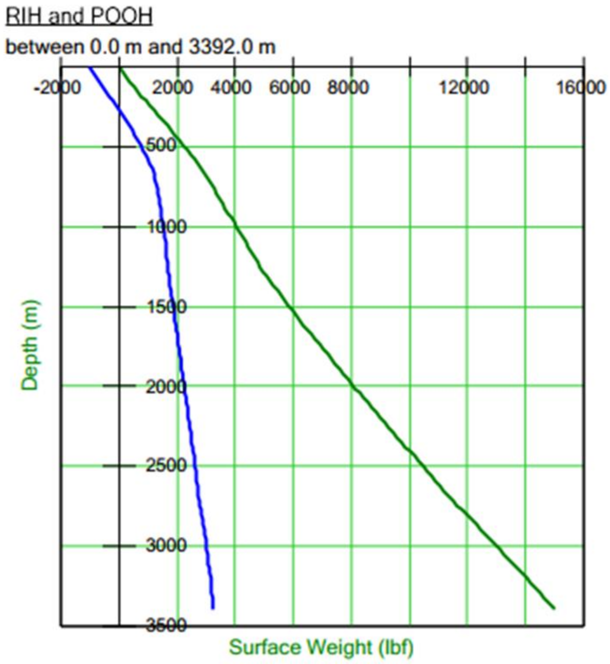


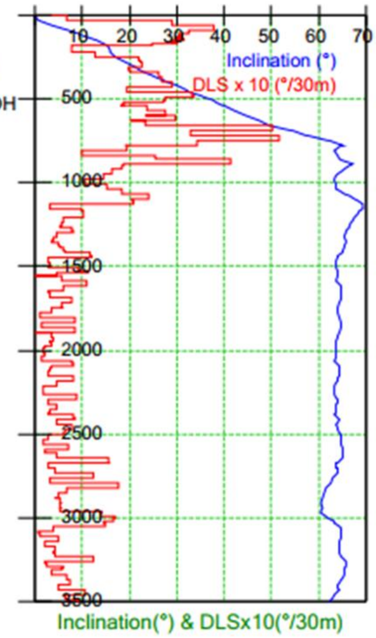


- Run #1 (Multijet Nozzle) with **Nitrified TIW (0.9 BPM and 400 scf/min)**



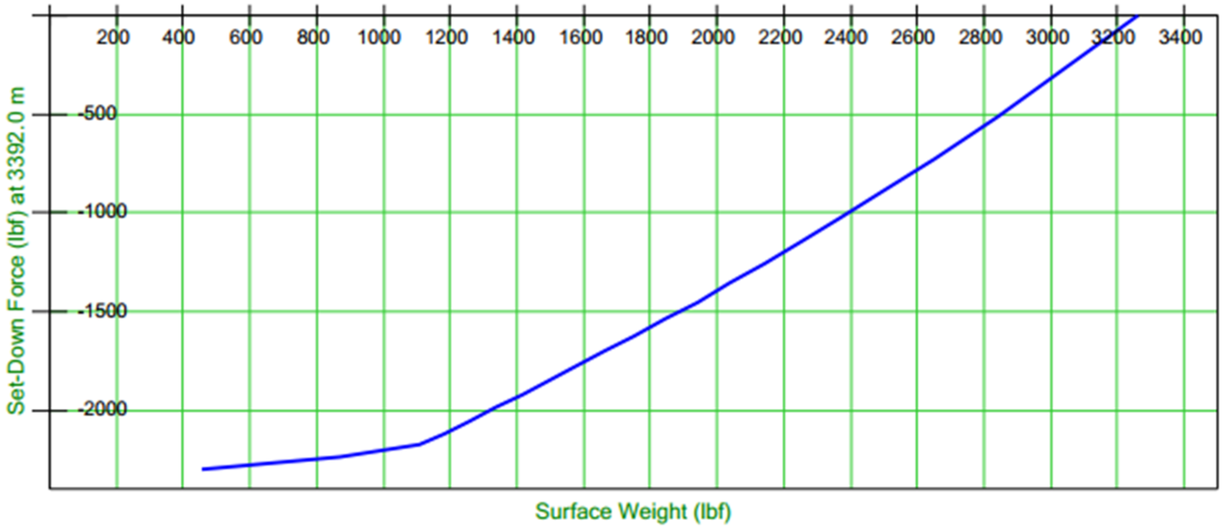
RIH & POOH WEIGHT





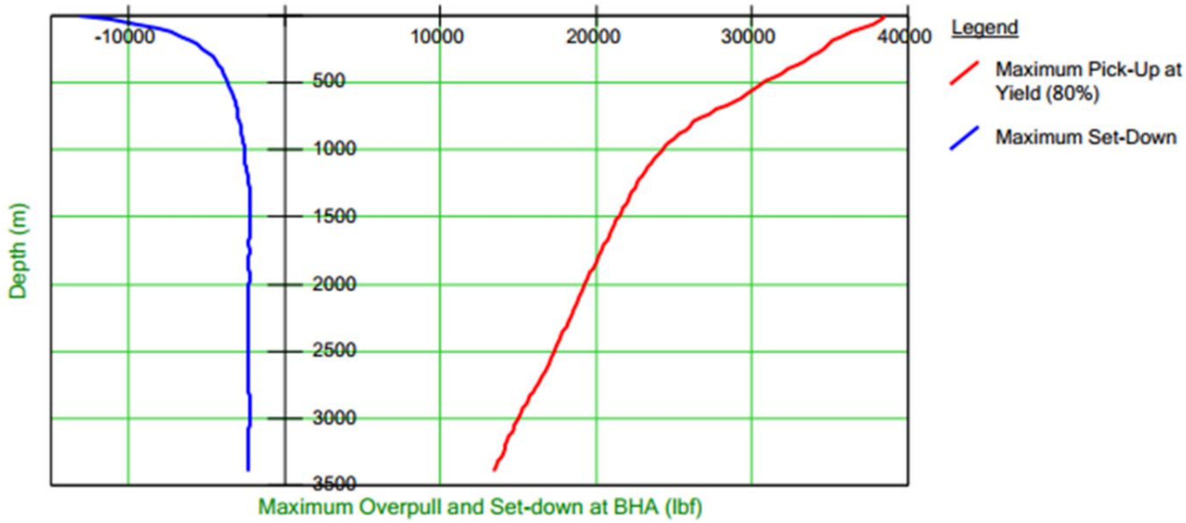
MAXIMUM STRING SET DOWN LIMIT

MD3 The available set-down force at 3392.0 m is -2297 lbf at the end of the string.
The weight indicator reading will be -1098 lbf on surface.
The minimum available set-down force is -2220 lbf at 1432.6 m.



MAXIMUM STRING PICK UP LIMIT

MD1 The available pick-up at 3392.0 m based on 80% of yield strength is 13419 lbf.
The weight indicator reading will then be 37344 lbf.



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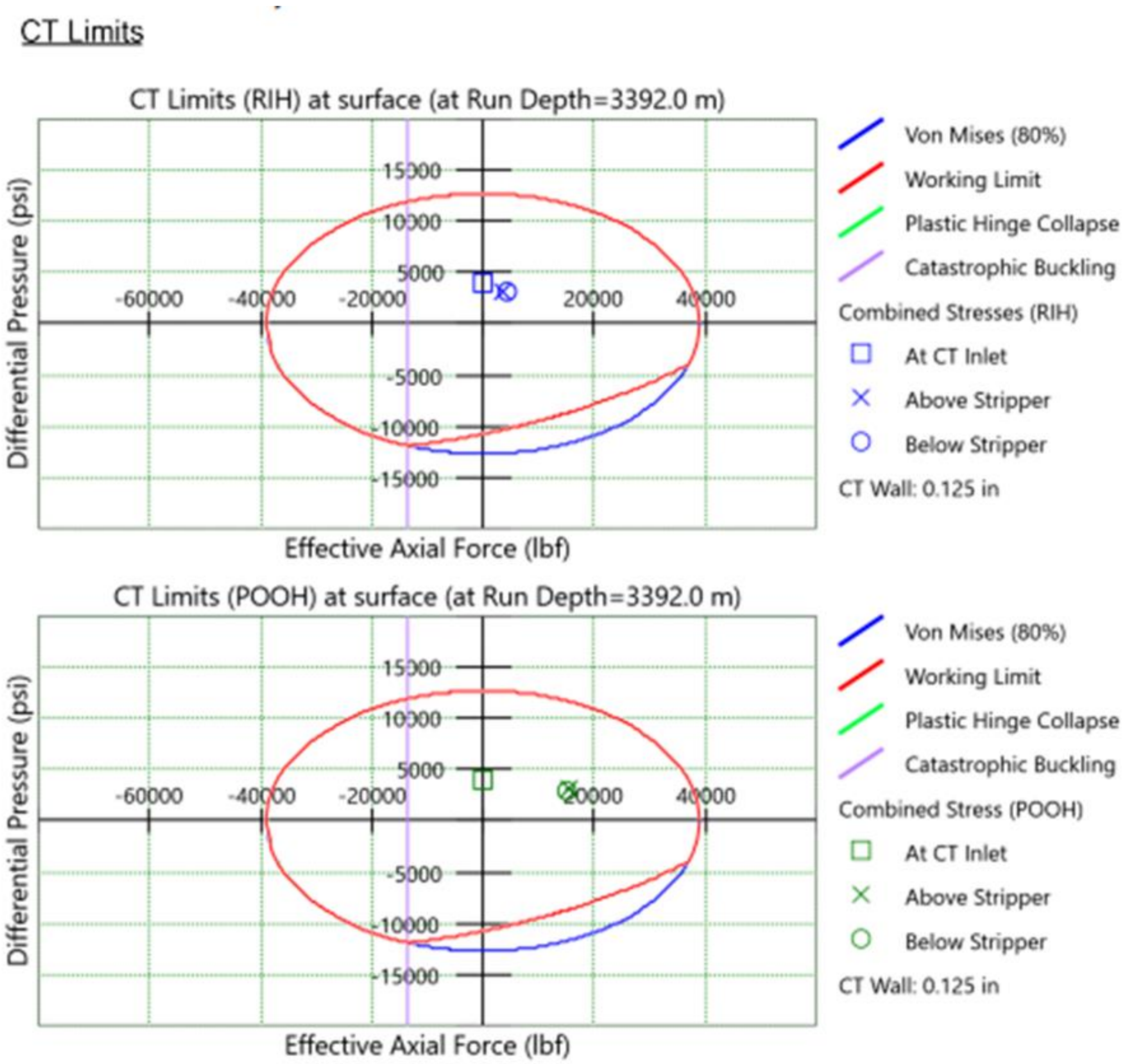
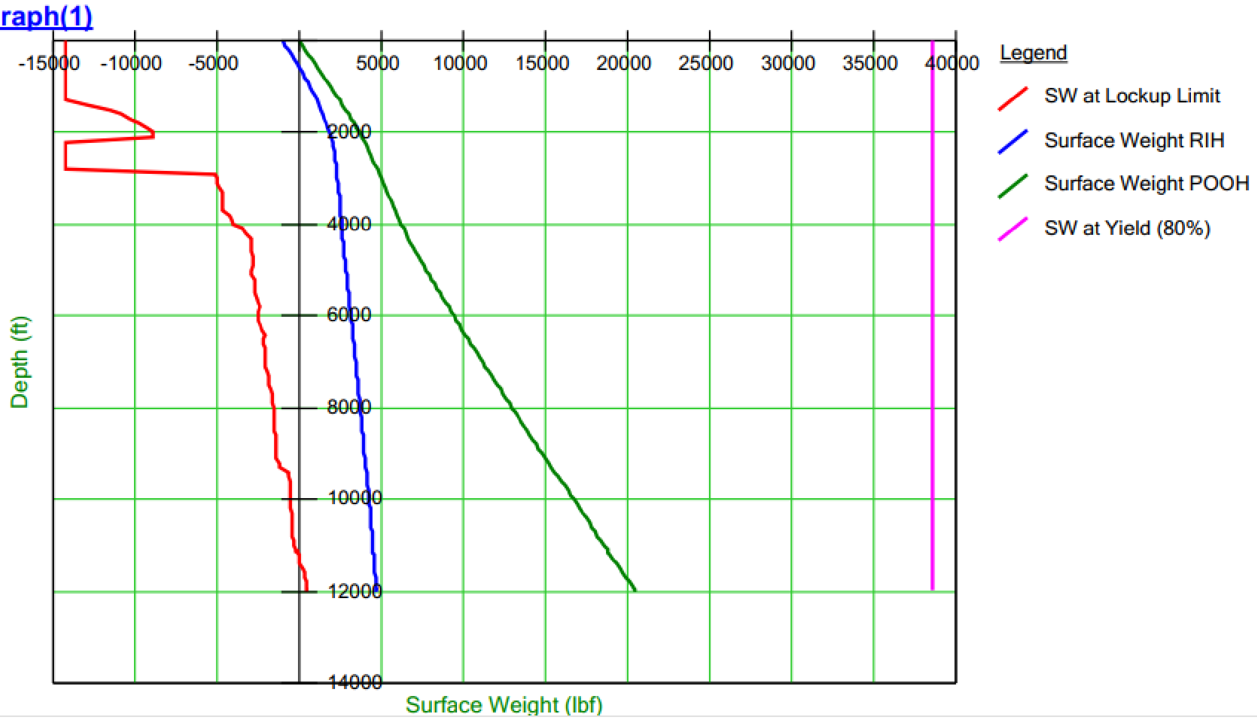
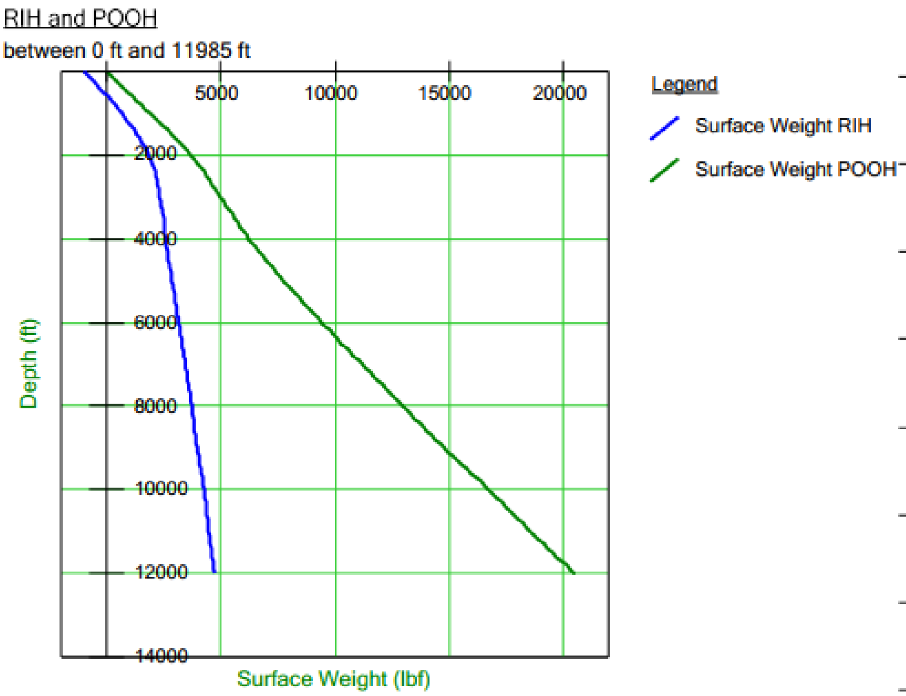


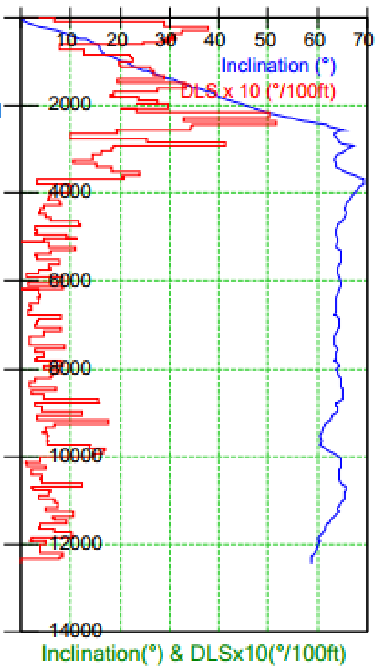
- Run #2 (Upward Jetting Nozzle) with **300 scf/min**

Graph(1)



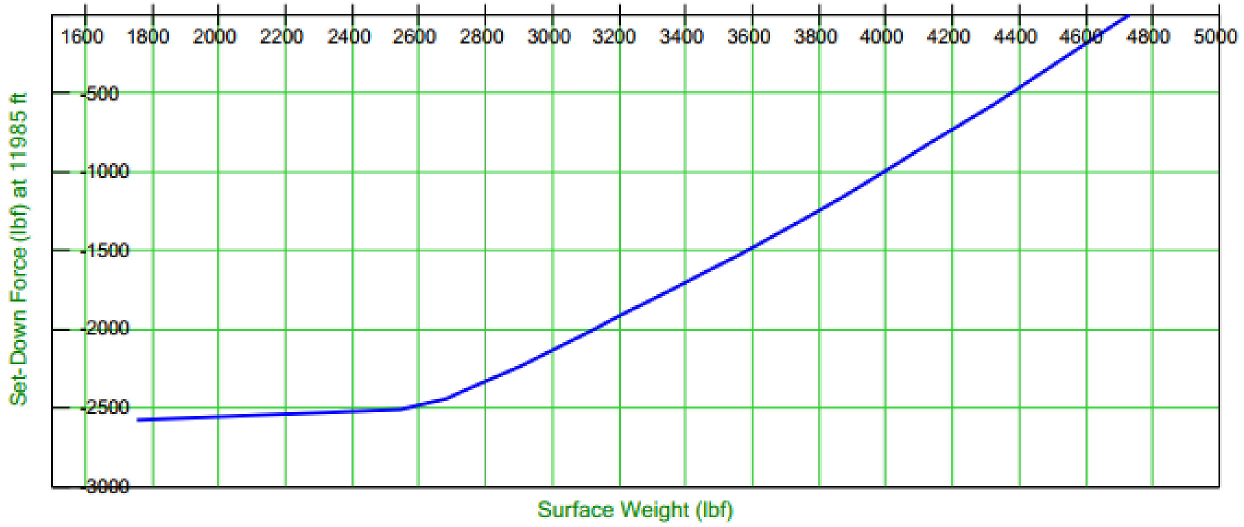
RIH & POOH WEIGHT





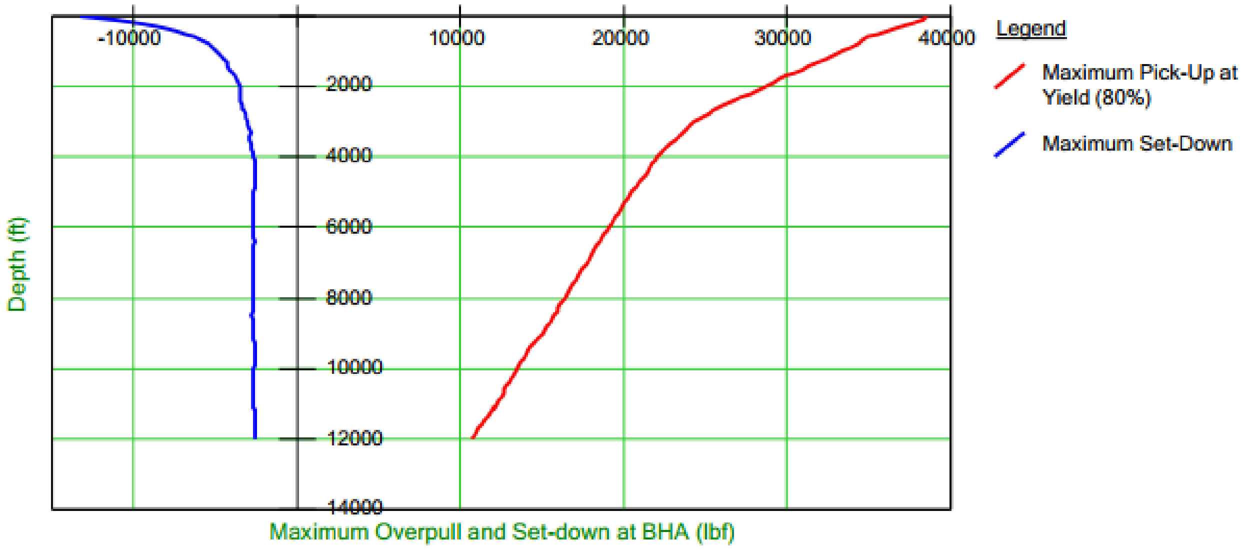
MAXIMUM STRING SET DOWN LIMIT

MD3 The available set-down force at 11985 ft is -2576 lbf at the end of the string.
The weight indicator reading will be 512 lbf on surface.
The minimum available set-down force is -2557 lbf at 11800 ft.



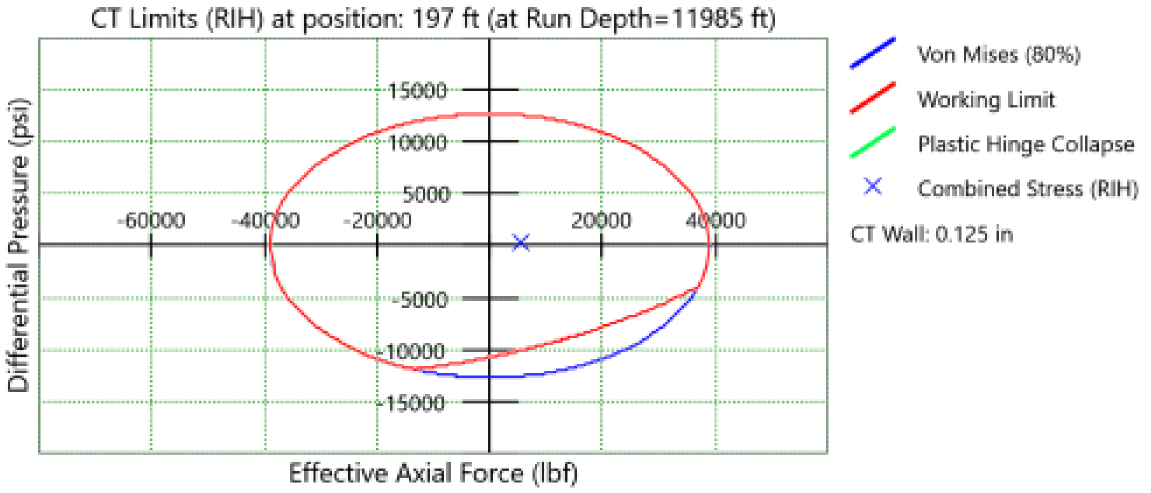
MAXIMUM STRING PICK UP LIMIT

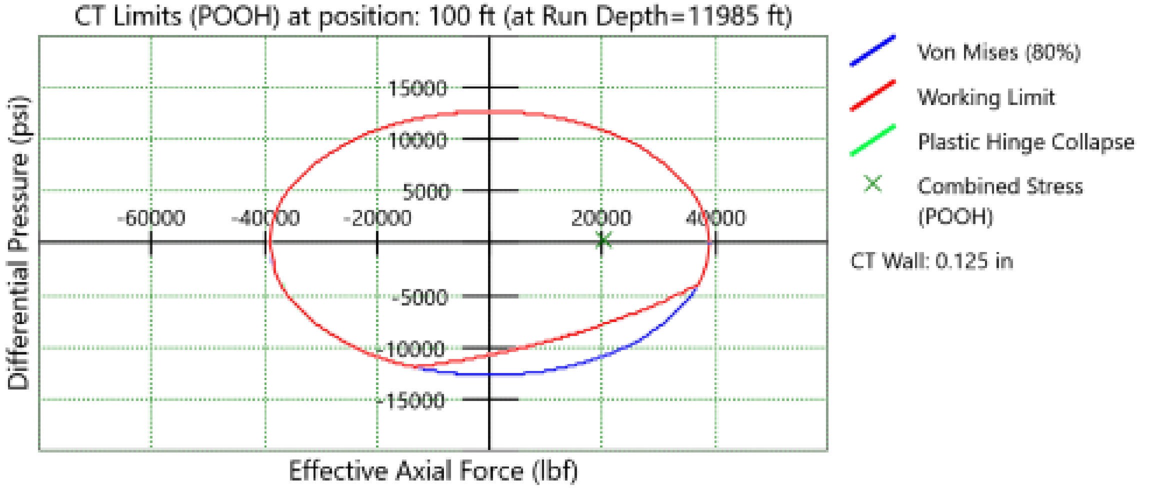
MD1 The available pick-up at 11985 ft based on 80% of yield strength is 10708 lbf.
The weight indicator reading will then be 38552 lbf.



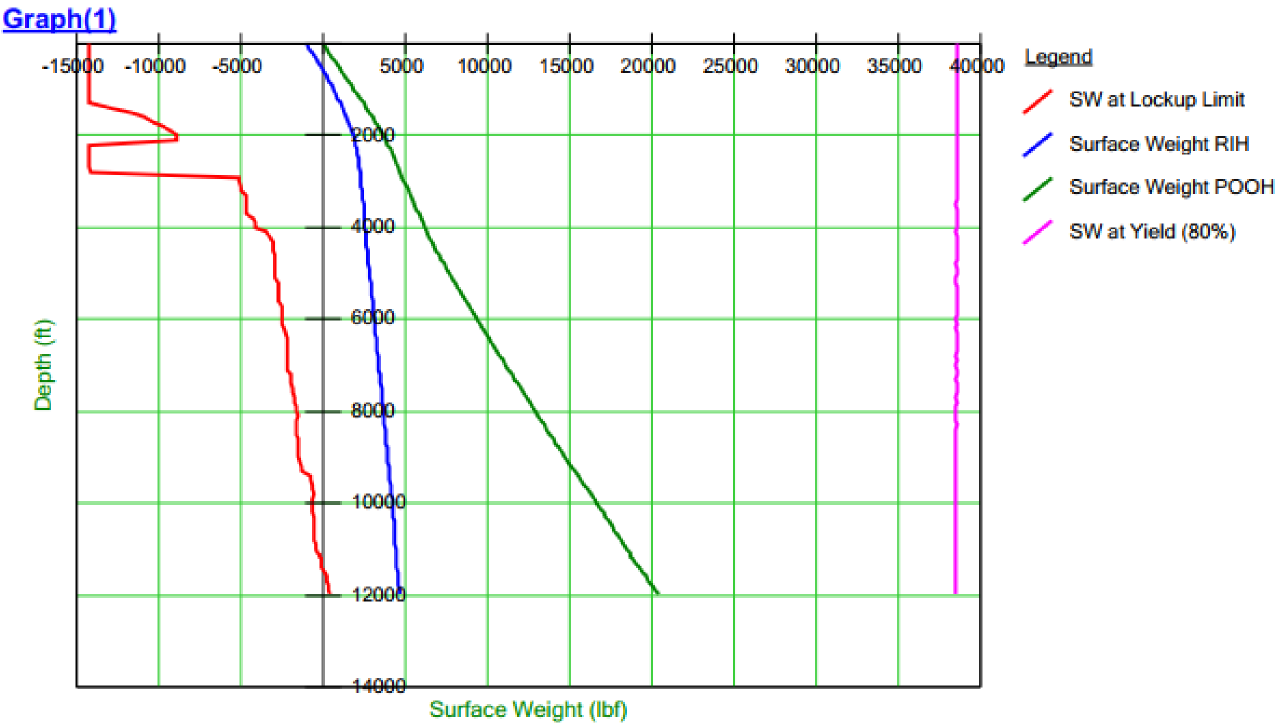
STRING LIMIT

CT Limits

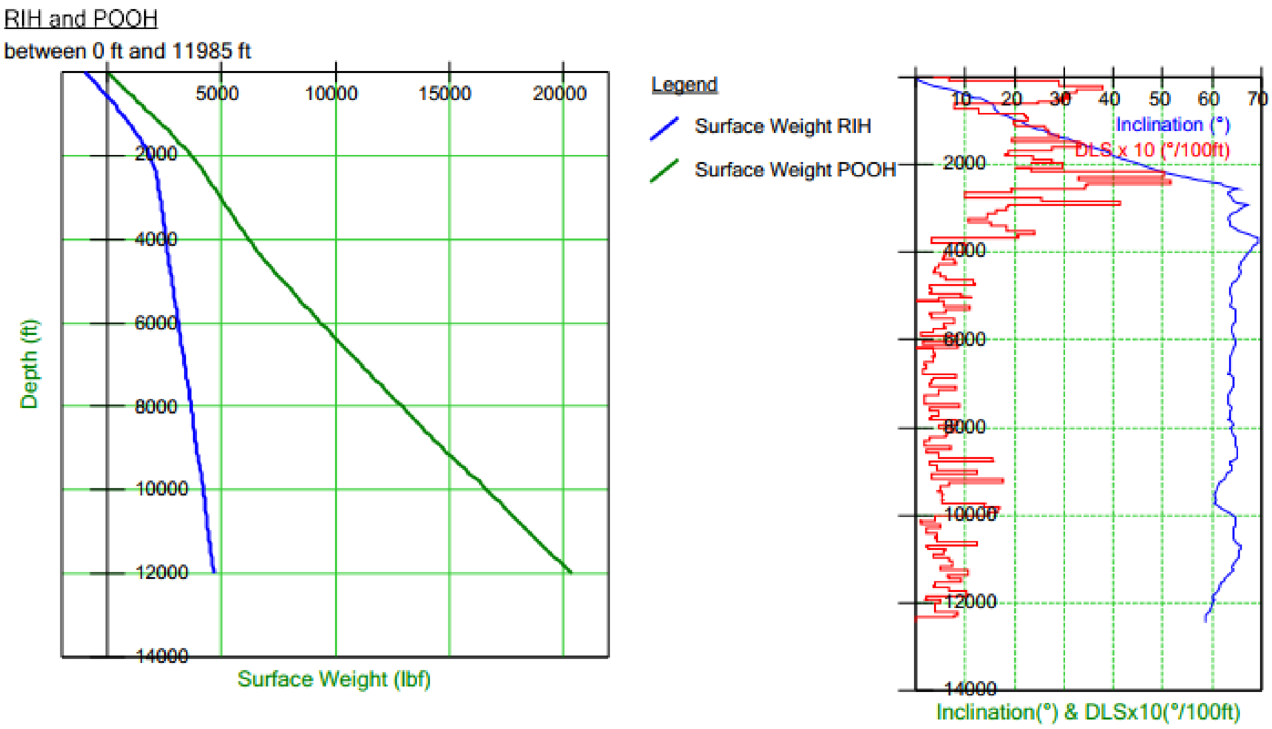




- Run #2 (Upward Jetting Nozzle) with **500 scf/min**

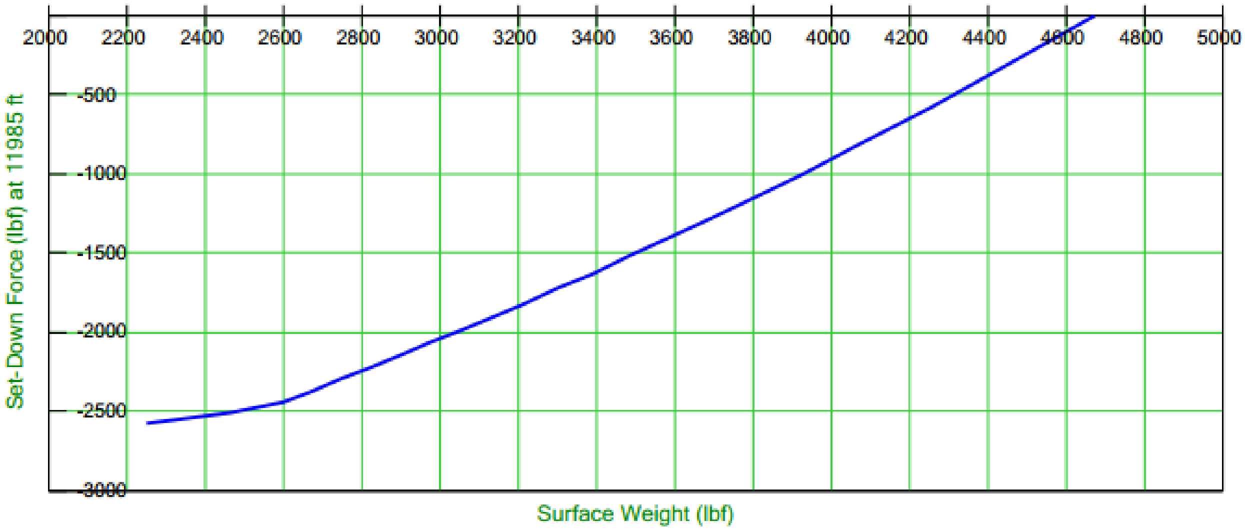


RIH & POOH WEIGHT



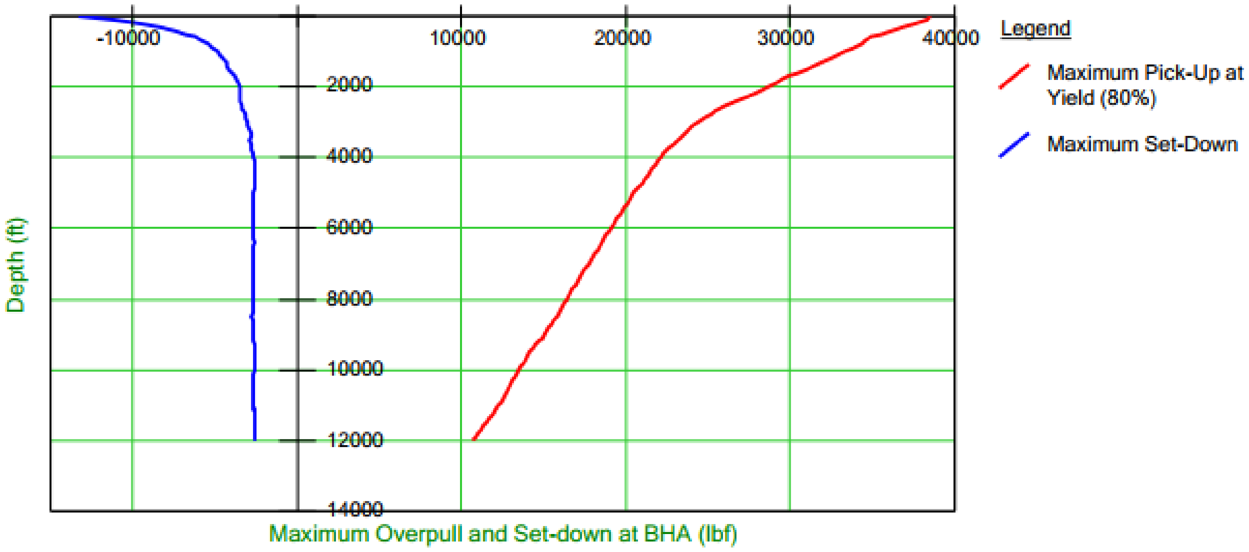
MAXIMUM STRING SET DOWN LIMIT

MD3 The available set-down force at 11985 ft is -2569 lbf at the end of the string.
The weight indicator reading will be 415 lbf on surface.
The minimum available set-down force is -2551 lbf at 11800 ft.



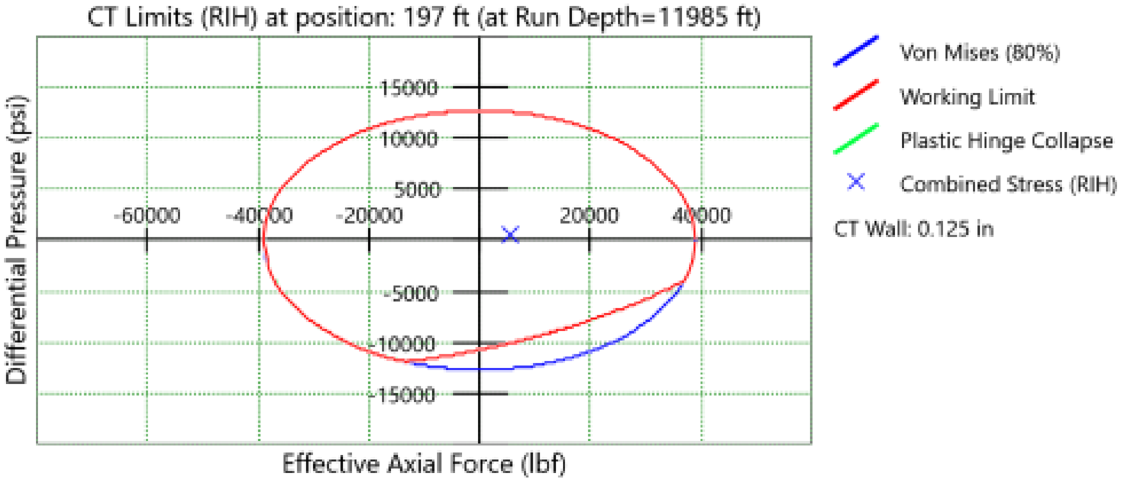
MAXIMUM STRING PICK UP LIMIT

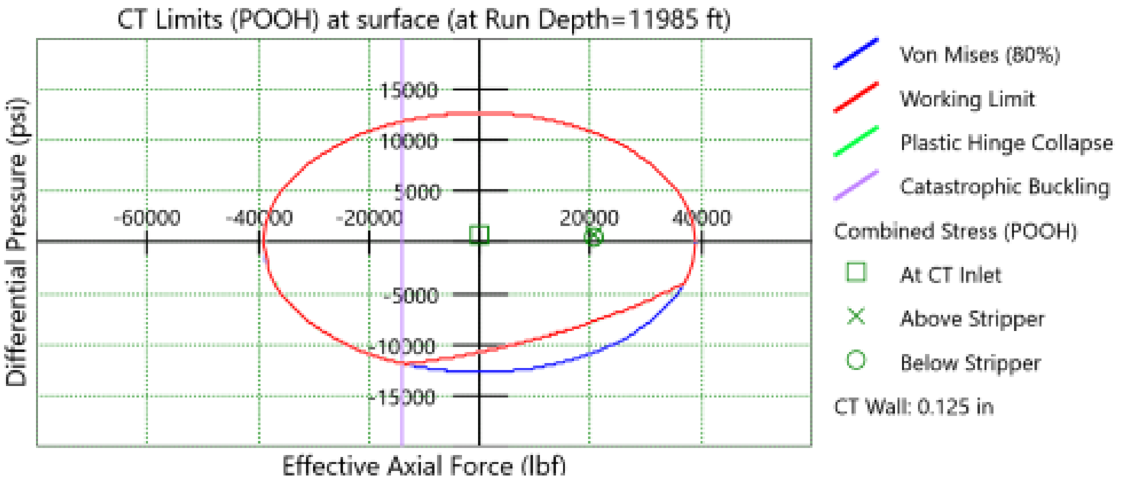
MD1 The available pick-up at 11985 ft based on 80% of yield strength is 10745 lbf.
The weight indicator reading will then be 38517 lbf.



STRING LIMIT

CT Limits





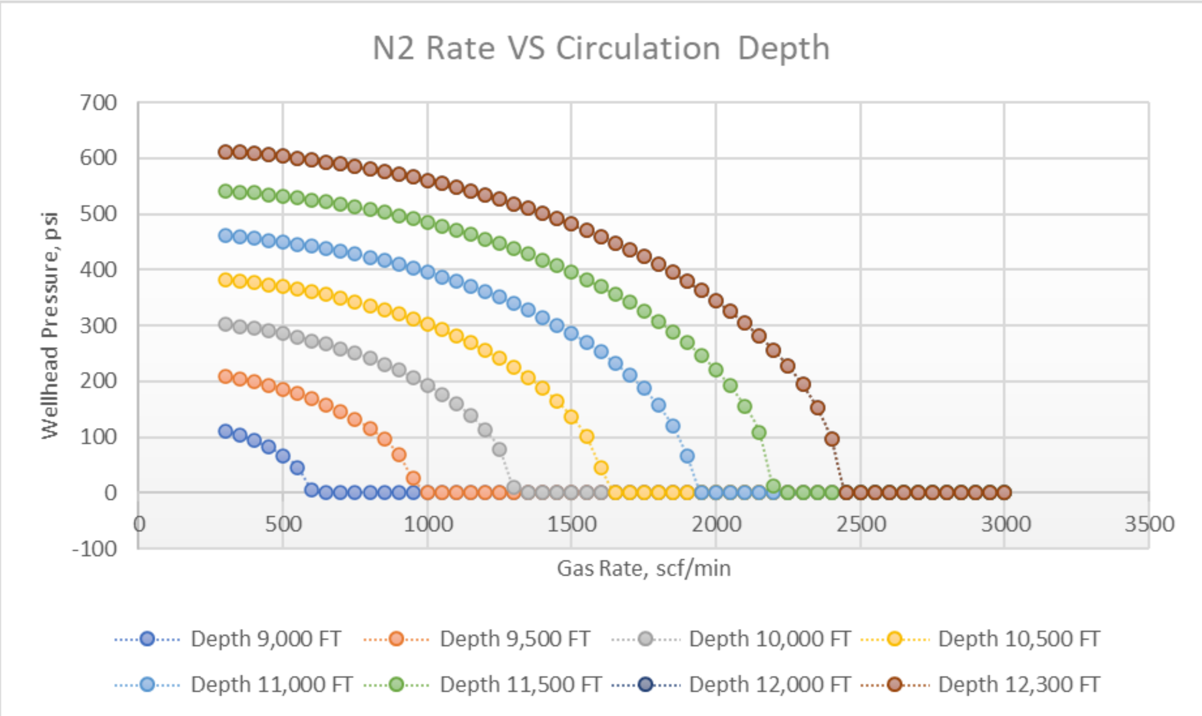
UNLOADING ANALYSIS

- Run #2 (Upward Jetting Nozzle) with **500 scf/min**

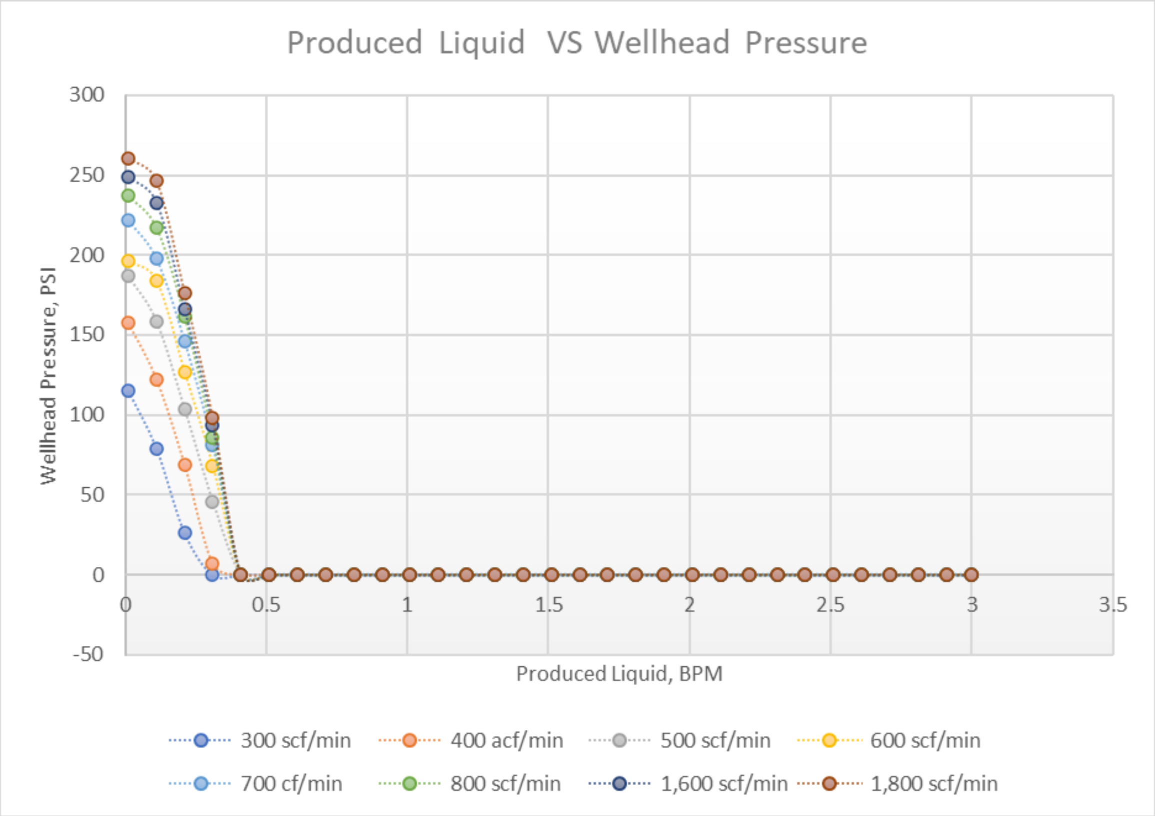
1. Depth analysis for nitrogen lifting for 1.5” CT size using average depth at 300 scf/min to evaluate on the depth.

BHA Depth ft	Completion Wellhead Pressure psi g	Perforation Pressure psi g	Completion Bottom Hole Pressure psi g	Circulation Point Pressure psi g	Workstring Injection Pressure psi g	Workstring Gooseneck Pressure psi g
3000	0.0	734.0	822.5	0.0	674.4	505.0
3500	0.0	734.0	822.5	0.0	672.7	510.9
4000	0.0	734.0	822.5	0.0	671.2	516.9
4500	0.0	734.0	822.5	0.0	669.5	522.7
5000	0.0	734.0	822.5	0.0	667.8	528.4
5500	0.0	734.0	822.5	0.0	666.1	534.0
6000	0.0	734.0	822.5	0.0	664.4	539.5
6500	0.0	734.0	822.5	0.0	662.6	544.9
7000	0.0	734.0	822.5	0.0	660.8	550.3
7500	0.0	734.0	822.5	0.0	659.0	555.5
8000	0.0	734.0	822.5	0.0	657.1	560.7
8500	0.0	734.0	822.5	57.8	655.4	566.1
9000	111.2	734.0	822.5	153.4	653.8	571.4
9500	208.7	734.0	822.5	257.9	652.0	576.6
10000	301.3	734.0	822.5	363.2	667.4	600.8
10500	382.8	734.0	822.5	458.2	700.8	644.0
11000	460.8	734.0	822.5	550.5	742.5	695.0
11500	541.7	734.0	822.5	648.0	793.1	754.2
12000	612.2	734.0	802.1	735.0	841.5	810.0
12290	612.2	734.0	739.9	737.7	840.8	812.2

2. Analysis on nitrogen injection rate depending on the depth for 1.5”CT.



3. Analysis on liquid production rate depending on the injection rates for 1.5”CT. Choosing the maximum depth at 11,985 ft MDDF (EOT).



APPENDIX IV – EMERGENCY PROCEDURE

EMERGENCY BOP OPERATIONS

In the event of an emergency arising and the well having to be secured, the following steps should be taken:

1. Stop Coiled Tubing movement, close the Slip and Pipe rams and slack off string weight to ensure slips are holding. If time permits, review all options with the client representative. (Ensure that rams with guides are activated first to avoid damaging the Coiled Tubing).

   Note: The decision to proceed past the above step should normally be made after consultation with the client representative unless there is an immediate and serious danger to personnel and/or equipment and the client representative is not immediately available to be involved in the decision.

2. Stop pumping.
3. Close the upper Shear Seal rams to cut the Coiled Tubing.
4. Set up to circulate well to kill fluid through the Coiled Tubing remaining in the well.
5. Make arrangements necessary to fish the Coiled Tubing from the BOP.

   Note: When actuating any ram in the BOP system, the corresponding manual lock should be closed behind it to prevent accidental release in the event of total loss of hydraulic power. The force required to close the rams manually against pressure cannot be supplied by turning in the locks. Use of a pipe wrench, cheater bars or snipes will damage the internal workings of the ram actuators. Some form of hydraulic power is required to operate the actuators. This pressure can be supplied via a hand pump or a hydraulic pump from any other piece of equipment on location, including a fluid pumper.

Actuating the BOP System Hydraulic Controls

1. Remove locks on control panel
2. Move the control lever to the desired position.
3. Push the BOP activate button supplying pressure to the circuit.
4. Observe the pressure drop in the hydraulic circuit and subsequent pressuring back up to system pressure as ram opens or closes completely.
5. Observe the ram indicator pins to verify the operation of the ram.
6. Close in the manual locks if required. (Flag system to indicate position of rams.)

The connections below the coiled tubing BOP must be all flanged. Should one of these connections start leaking, the following steps should be taken in consultation with the client representative:

1. Call local alert and ensure all personnel are removed from the wellhead area.
2. Notify the client representative of the problem and determine the best method to make the area safe.
3. If the leak is minor, it may be possible to continue to pull the coiled tubing to surface. Assess the scenario and consider all the risks associated then proceed to pull the coiled tubing to surface. Once at surface, close available valves below the leak point.
4. If the leak is more severe, initiate a well kill through the well kill line and continue to pull the coiled tubing to surface.
5. If the leak is catastrophic, run the coiled tubing to HUD; pick up sufficient so that after the coiled tubing is cut at surface by CT BOP shear; the top of the coiled tubing falls below the X-mass Tree. Once the end of the coiled tubing is off bottom, proceed to cut the cut the coiled tubing with the shear RAM then close the available valves below the leak point. A well kill operation can be started through the kill line if requested by the client representative.

LEAK IN COILED TUBING AT SURFACE

In the event of a leak in the Coiled Tubing occurring at surface, the following steps should be taken:

1. Call local alert and ensure all personnel are removed from the operational area. In particular make sure all personnel remain clear of the area between the Injector Head and the Coiled Tubing reel.
2. If the leak is small or a pinhole leak, POOH and position the leak on the lower part of the Coiled Tubing reel as soon as possible. Be careful when area of leak is bent onto the reel as failure may occur. Make arrangements to have a water hose present to wash away any fluid from the reel which may be hazardous. Make arrangements to start pumping water through the Coiled Tubing reel. Depressurize reel as much as conditions allow without exceeding collapse limitations of Coiled Tubing.
3. Notify client representative of problem and determine best method to make area safe. If leak is minor and water can be displaced to leak, continue to POOH and change reel.
4. If leak is considered to be too serious to displace to water and POOH, or serious and uncontrolled leakage of hydrocarbon or hazardous materials prevents this, (i.e. check valves not holding, lost BHA, parted Coiled Tubing) set the Coiled Tubing slips and pipe rams. Activate the upper Shear Seal rams on either the triple or quad BOP and manually lock in place.
5. Depressurize the Coiled Tubing reel and flush through the reel. If hydrocarbons are present in the reel, displace the reel with water and empty the contents to specified safe disposal area.

LEAK IN COILED TUBING BELOW SURFACE

If a leak occurs in the Coiled Tubing below the Stuffing Box during down hole operations (usually indicated by a drop in pump pressure or loss of string weight), suspend Coiled Tubing operations and alert the client representative.

Note:

If indications are that the BHA has been lost in hole then revert to section 0.

1. Once the client representative has been alerted, clear all personnel from the immediate area of the Coiled Tubing around the Injector Head and between the Injector Head and the Coiled Tubing reel.
2. Displace the Coiled Tubing to water and commence to POOH at not more than 20 ft per minute (5 meters/min). Ensure at all times that all personnel are clear of the immediate area as the possibility exists to pull the Coiled Tubing out of the Stuffing Box. Continue pumping water at a slow rate through the Coiled Tubing.
3. When the leak in the Coiled Tubing appears above the Stuffing Box, stop the injector and hold the leaking section of Coiled Tubing between the chains and the Stuffing Box.
4. Inspect leak. If leak is minor continue to POOH.
5. If leak is major, or Coiled Tubing is actually severed or well bore fluids are escaping through the Coiled Tubing, continue as per Section 09.2.

LEAK IN SURFACE PRESSURE CONTROL EQUIPMENT

Stuffing Box

1. **Stop** Coiled Tubing movement and close both sets of pipe rams to seal Coiled Tubing annulus. Set manual lock.
2. On semi submersible operations this will be a set of pipe rams and pipe/slip rams.
3. Notify Client representative.
4. Ensure the injector is in neutral and that the brake is engaged.
5. Bleed off pressure above pipe rams
6. Set reel brake. On Semi Submersible jobs the Coiled Tubing should be clamped at the level wind and Coiled Tubing run out of hole until enough slack between the injector and reel is obtained to cope with the heave from the rig, prior to setting reel brake.
7. Bleed off closing pressure on Stuffing Box. Open side doors and apply pressure to retract piston. Replace packer elements and then re-apply pressure to Stuffing Box. Close side doors.

   Note: 3" side door Stuffing Boxes first bleed off closing pressure. Remove hoses from pack and retract piston and connect to open and close on side door. Open door and replace packer element. Close door, bleed off pressure and connect to pack and retract piston.
8. Slowly open both equalizing valve on pipe rams and check that stripper is holding pressure.
9. If stripper is holding pressure, undo manual locks and open pipe rams or pipe slip rams. When using pipe/slip rams the depth that they were set on the Coiled Tubing must be recorded. Release reel brake and continue operations.

Surface Leaks Other Than Stuffing Box

1. If leak is minor and a relatively short length of Coiled Tubing is in the hole and the Shear Seal safety head is **below the leak:**
2. Call local alert and notify the client representative.
3. Clear all non-essential personnel away from the area
4. Continue POOH and monitor situation closely
5. Hook up kill line to BOP and pump water slowly down annulus.

Note: Avoid collapse situation

1. Close swab valve and Shear Seal once Coiled Tubing is in riser and repair leak
2. Perform reinstatement test on surface equipment after leak has been repaired
3. If Coiled Tubing is in the well to a considerable depth and leak is considered serious:
4. Call local alert and notify Client representative.
5. Ensure all non-essential personnel are removed from the area.
6. Ensure that Coiled Tubing is sufficiently off bottom so that when the Shear Seal safety head is activated the pipe will drop below the Xmas tree manual master valve. If the Coiled Tubing is stuck down hole, pull to 80% of operating limit before activating Shear Seal BOP, thus allowing the Coiled Tubing to drop below the Xmas tree manual master valve. If the Coiled Tubing is attached to a fish, packer etc pull to 80% of operating limit (if possible) or maximum weight possible before activating Shear Seal BOP, thus allowing the Coiled Tubing to drop below the Xmas tree manual master valve. **If at all possible**, the decision to cut the Coiled Tubing and activate the system will be taken by the Client representative in charge of the operation. This may not always be possible. If the situation is extremely dangerous and requires a fast decision, the Supervisor in charge will take this decision.

7. Close the Shear Seal rams in the safety head to cut the pipe and allow it to drop. (If the safety head has separate shear and blind rams, close the shear rams to cut the pipe, pull up the Coiled Tubing and close the blind rams).
8. Close the swab valve on the Xmas tree.
9. Close the master valve on the Xmas tree
10. Repair leak and pressure test riser.
11. Plan for fishing operations.

Rotating Joint Leak

Eliminate the potential for reel movement by securing the reel with turnbuckles and set reel brake. On Semi-Submersible jobs the Coiled Tubing should be clamped at the level wind and Coiled Tubing run out of hole until enough slack between the injector and reel is obtained to cope with the heave from the rig. Close the reel isolation valve inside the reel and repair or replace the rotating joint as required. Re-test and resume operations.

COILED TUBING RUNS AWAY INTO WELL

If the inside chain tension system on the Injector Head should fail for any reason, and Coiled Tubing is pulled into the well under its own weight with no control, the procedure should be as per the following:

1. Call a local alert.
2. Attempt to speed the injector up to match the speed of the descending Coiled Tubing.
3. Increase inside chain tension to increase friction on Coiled Tubing.
4. Increase stripper pressure to exert more friction on Coiled Tubing.
5. If these actions fail to make any difference, reduce injector hydraulic pressure to zero.
6. In the event that there is insufficient Coiled Tubing on the reel to reach bottom close Coiled Tubing slips. This action may damage or break the Coiled Tubing. This is the preferred option to using the pipe rams as these will become damaged and a primary well control system will be lost.
7. If the Coiled Tubing is not too far off bottom it may be practical to let it fall to bottom then investigate the causes and repair. This can only be done if there is sufficient Coiled Tubing on the reel to reach bottom.

Note: Coiled Tubing may helix when hitting bottom making it difficult to pull into tail pipe.

8. Once Coiled Tubing has been controlled, examine Injector Head for damage including chains and POOH.
9. The Coiled Tubing run away may be caused by the injector becoming overloaded with the weight of the Coiled Tubing and fluid in the Coiled Tubing. This situation should not occur if proper pre job planning is done. Correct selection of Injector Head or ensuring Coiled Tubing is full of Nitrogen would prevent this situation from occurring.
10. If a run away situation occurs, reduce the injector hydraulic pressure to zero. This may cause the safety brake in the motors to actuate and counter balance valves to close, stopping the injector.
11. Under certain circumstances if the run away Coiled Tubing is at a speed above the critical speed, the back pressure created by the circulating hydraulic fluid may prevent the injector motor brakes from actuating. If this situation occurs, select the pull mode for the injector and increase system hydraulic pressure until the Coiled Tubing comes to a standstill.

COILED TUBING IS PULLED OUT OF STUFFING BOX

This situation is most likely to occur when the Coiled Tubing is being pulled into the riser section. If the BHA is lost including the End Connector there will be no external upset to prevent the Coiled Tubing from passing through the Stuffing Box. If this situation occurs, stop injector before Coiled Tubing passes through the chains and shut in Shear Seal rams on upper BOP's.

If it is thought that the BHA may be lost while down hole, stop the Coiled Tubing at 300ft from surface. Slowly close in the swab valve counting the number of turns. If the Coiled Tubing is still deemed to be across the wellhead, POOH the Coiled Tubing no more than the distance between the top of the wellhead and the top of the Coiled Tubing BOP's. Repeat this step until the swab valve can be fully shut. Once the swab valve is shut, bleed off the pressure in riser.

COILED TUBING COLLAPSED AT SURFACE

Collapsed Coiled Tubing at surface will be obvious by escape of well bore fluids from the Stuffing Box, as the strippers will no longer seal round the deformed pipe. In addition to this the collapsed pipe will not allow the Injector Head to grip the Coiled Tubing due to its change in shape. Usually collapsed Coiled Tubing will not pull through the bottom brass bushings on the Stuffing Box.

1. If POOH, immediately run Coiled Tubing back in well a sufficient distance to make sure round pipe is in contact with the Stuffing Box.
2. Call alert and notify client representative.
3. Ensure that all non-essential personnel are cleared from the immediate area.
4. Immediately reduce well head pressure by all safe means possible; either flow well through choke at a higher rate or stop annular fluid injection if reverse circulating.
5. Increase Coiled Tubing internal pressure by circulating.
6. Once pressure conditions inside and outside the Coiled Tubing have been optimized, a decision can be taken on how to proceed. If it is not possible to position uncollapsed pipe across the stripper rubbers, i.e. well contents are escaping from stripper rubbers:
7. Call alert and notify client representative.
8. Close pipe rams in an effort to reduce flow of fluid/gas around Coiled Tubing.

Note: If it is not possible to control the well, the slips will have to be set, and the Coiled Tubing cut using the Shear Seal rams.

9. Arrange for clamps to be fitted to Coiled Tubing above Injector Head.
10. Remove all non-essential personnel from immediate area
11. Under authority from client representative, kill well.
12. Release pressure from Stuffing Box and remove bushings.
13. Open pipe rams.
14. Attempt to pull Coiled Tubing from the well using the Injector Head.
15. Cut Coiled Tubing at the gooseneck and use the rig or a crane to pull the Coiled Tubing through the injector. Re-clamp the Coiled Tubing above the Injector Head and cut off in thirty foot sections (or as appropriate to the crane or rig)
16. Continue pulling and cutting Coiled Tubing until the Coiled Tubing pulled to surface can be pulled by the Injector Head.

17. Once Coiled Tubing in good condition (i.e. not collapsed) is at surface, set Coiled Tubing slips and pipe rams and make up roll-on connector to Coiled Tubing on reel.
18. Continue POOH.

If the leak is too serious and cannot be controlled and well fluids are escaping, continue as per Section 9.2.

COILED TUBING BREAKS AT SURFACE

If Coiled Tubing breaks at surface into two separate sections:

1. Stop the injector and set the slips.
2. Stop pumping operations.
3. Call alert and notify client representative. Ensure all non-essential personnel are cleared from the area and that the area is secure.
4. Secure Coiled Tubing reel.
5. If the reel capacity is insufficient to hold all of the Coiled Tubing remaining in the well due to uneven spooling resulting from the Coiled Tubing failure, it may be necessary to obtain another reel with sufficient capacity to hold the Coiled Tubing remaining in the well.
6. After consulting with client representative, remove damaged section of Coiled Tubing and insert in line roll-on connector and continue to POOH.
7. If this course of action is considered inappropriate or dangerous due to well conditions or condition of Coiled Tubing still in the well, continue as per Section 0.

BUCKLED TUBING

Should the Coiled Tubing hit an obstruction down hole while RIH with the thrust pressure set too high or running speed too fast, the Coiled Tubing will buckle in a ‘Z’ shape (plastically hinged).

Coiled Tubing being run inside Coiled Tubing and through small ID BOP’s/lubricators will normally buckle between the Stuffing Box and the chains.

Coiled Tubing being run through casing or open hole will normally break below the BOP, usually somewhere around the largest ID.

- The Coiled Tubing will generally buckle several times.
- This type of failure is a little more difficult to detect.

If the Coiled Tubing is being run into casing and a large amount of weight is lost suddenly, there is a very good possibility that the Coiled Tubing is buckled somewhere down hole. Indications of this could be:

- An increase in pump pressure as fluid or gas is now being pushed through an additional restriction created by a hinge.
- A decrease in pump pressure as the Coiled Tubing may have broken removing a restriction such as a BHA.
- A loss of string weight due to the Coiled Tubing breaking and falling off.
- An increase in string weight while pulling out of the hole as the buckled portion of Coiled Tubing creates additional drag or needs to be straightened to get through a restricted ID.

In the event Coiled Tubing buckling is suspected, the Coiled Tubing movement should be stopped and the pump pressure kept within operating limits allowing the situation to be analyzed and determine the correct action to be taken for existing conditions.

If there is an increase in pump pressure or an increase in string weight:

1. Stop the pumps and pick up slowly.

2. POOH slowly (10 to 20 feet per minute) watching the weight indicator carefully.
3. If the Coiled Tubing is buckled close to surface, the buckled Coiled Tubing will pull into the bottom of the Stuffing Box and stop.
4. Close and lock the slip and pipe rams.
5. If the ram indicators show that the rams are not completely closed, there may be more than one piece of Coiled Tubing inside the BOP. In this event, open the rams and try to put undamaged Coiled Tubing across the pipe and slip rams.
6. Make arrangements to kill the well and retrieve the remaining Coiled Tubing from the well.
7. If the buckled Coiled Tubing is down hole and cannot be pulled free, consult the client representative as he may want the Coiled Tubing left at TD prior to being hung off in the slip and Coiled Tubing rams.
8. Arrangements should be made to run Coiled Tubing cutter on wireline to retrieve the Coiled Tubing above stuck point.

If there is a decrease in pump pressure or a loss of string weight:

1. It must be assumed that the Coiled Tubing has parted somewhere down hole.
2. Calculate from the remaining string weight approximately how much Coiled Tubing is left in the well.
3. Stop the pumps and POOH slowly.
4. Should the Coiled Tubing come out of the Stuffing Box, the blind rams should also be closed in.

If the Coiled Tubing is buckled above the Stuffing Box, the following steps should be taken:

1. Stop the injector as quickly as possible.
2. Close the slip and pipe rams and manually lock them.
3. If the down hole check valves are holding, bleed the pressure in the Coiled Tubing down to zero and monitor for 15 minutes for pressure build up.
4. Consider at this stage whether to kill the well.
5. Use a hacksaw to start the cut until you are sure there is no trapped pressure in the Coiled Tubing.
6. Cut the Coiled Tubing
7. Remove as much of the buckled Coiled Tubing as possible leaving any undamaged Coiled Tubing showing above the Stuffing Box intact so that it may be rejoined later.
8. Bleed the pressure from above the Coiled Tubing rams and undo the connection below the injector.
9. Slowly raise the injector until it is clear of the damaged Coiled Tubing.
10. Cut away any damaged Coiled Tubing, dress the Coiled Tubing and install an inline connector.
11. Run some fresh Coiled Tubing down through the injector until it is just out of the Stuffing Box.
12. Lower the injector until immediately over the pipe sticking out of the BOP.
13. Attach the pipe to the inline connection attached to the pipe sticking up out of BOP.
14. Pump off the inside chain tension and rotate the chains slowly in the OOH direction, while lowering the injector until the connection below the injector can be fastened.
15. Pump up the inside chain tension and pull weight equal to the weight of the Coiled Tubing suspended below the slips plus 2,000 lbf for friction or CERBERUS prediction, whichever is greatest.
16. Equalize the pressure across the Coiled Tubing rams.
17. Unlock the pipe and slip rams.
18. Open the slip and pipe rams and POOH.
19. If the down hole check valves do not hold then the Coiled Tubing will have to be cut.

COILED TUBING STUCK IN HOLE PROCEDURES

There are various scenarios by which Coiled Tubing can be deemed as a stuck in hole situation. The following procedures are to be used as generic guidelines prior to the compilation of a signed off chemical cutting program applicable to the current situation.

In the event of being stuck in hole, several factors would have to be taken into consideration, the first of which would be whether the Coiled Tubing is stuck in hole on a platform, or a semi-submersible, as the procedures to be followed may vary greatly between the two options.

Other factors to be considered are:

- Type of well, i.e. flowing oil or gas well, water injector etc.
- The type of BHA being used, i.e. perforating guns, milling assembly, plug etc.
- The type of operation being carried out when the Coiled Tubing became stuck.

In all of the above cases, the Coiled Tubing would be defined as being "stuck" when the pipe cannot be retrieved from the well bore without the pipe exceeding its 80% minimum yield rating, or without exceeding 80% stress of the weak link release rating. The lower of these two factors should always be used when attempting large pulls.

Regardless of the specifics involved, the following procedures should be adopted:

1. Inform the client representative of the situation.
2. Inform the Onshore Engineer.
3. From the information available, and taking into account the well conditions, try to determine the reason for the pipe/BHA being stuck.
4. Attempt to pull free by applying a steady pull to a maximum of 80% of the Coiled Tubing yield. If in doubt as to what this figure is, consult Engineering Department before proceeding.
5. When applying the maximum pull, hold the maximum value for a minimum of 10 minutes and observe the trend (if any) on the weight indicator and chart. Measure the amount of pipe extension that is required when this pull is applied. The figure can be used to determine where the Coiled Tubing is stuck. As a rule of thumb, the depth that the pipe is held at will be the extension of the Coiled Tubing (in feet) when pulled to 80% of yield divided by 0.002. This can be determined using CERBERUS.

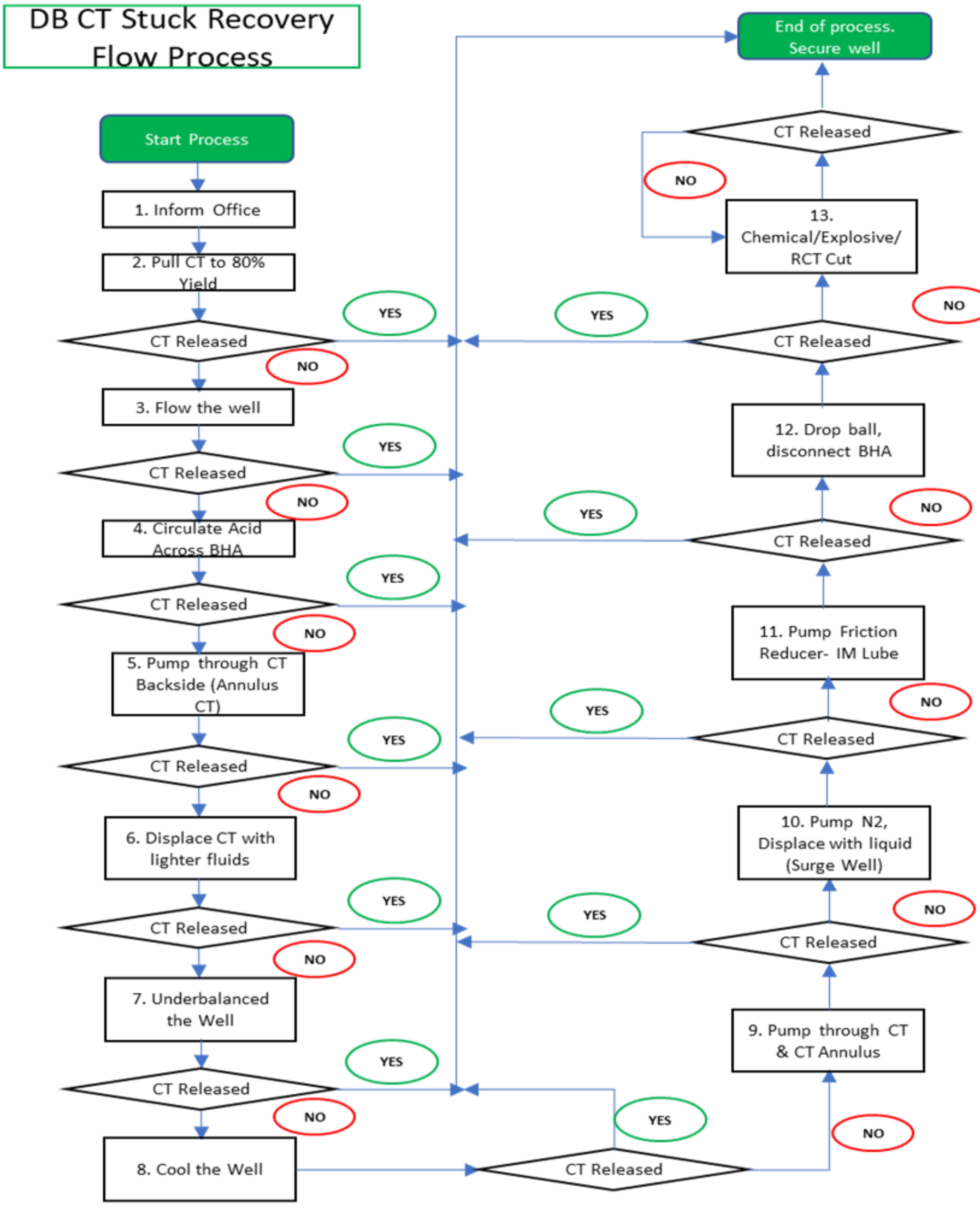
The following are options that may be appropriate depending on the particular circumstances:

1. If possible, flow the well, or increase well flow in an effort to remove debris in the well bore that may be holding the Coiled Tubing/BHA. Maintain maximum circulation through the Coiled Tubing at the same time. This is particularly relevant if well cleanout or drilling operations have been performed.
2. Circulate acid across the BHA in an attempt to remove any acid soluble material that may be holding the Coiled Tubing.
3. Pump fluid down the backside of the Coiled Tubing to the formation in an attempt to dislodge debris from around the BHA. Potential Coiled Tubing collapse must be considered if engineering this scenario.
4. Displace Coiled Tubing contents to a lighter fluid (base oil) or gas (Nitrogen) to increase buoyancy and allow greater end force to be applied at BHA.
5. Underbalance the well in the case of differentially stuck Coiled Tubing.
6. Cool the well if the Coiled Tubing is helically stuck in corkscrewed Production Tubing.
7. Pump down the Coiled Tubing / completion annulus to try and move the source of hold-up.
8. Displace slugs of Nitrogen with water to create a surge effect at the BHA.

9. Pump friction reducer, IM Lube in seawater at 2-3% by volume, down the Coiled Tubing and into the well. Ideally, one well volume will be pumped.
10. After consultation with the client representative and the on call Engineer, activate the emergency disconnect mechanism in the BHA to allow the Coiled Tubing to be released. The release mechanism should only be implemented after all avenues have been explored.
11. When attempting maximum pull, do not work the Coiled Tubing violently across the gooseneck by frequent intervals.
12. The amount of cycles across the gooseneck must be logged, and if in doubt of the Coiled Tubing fatigue condition, the Engineer must be consulted and the cycles entered into the CERBERUS FATIQUE program, to determine the amount of cycles left available.

After consultation with the client representative, kill the well and commence preparations for chemical cutting operations.

STUCK CT COIL RECOVERY PROCESS

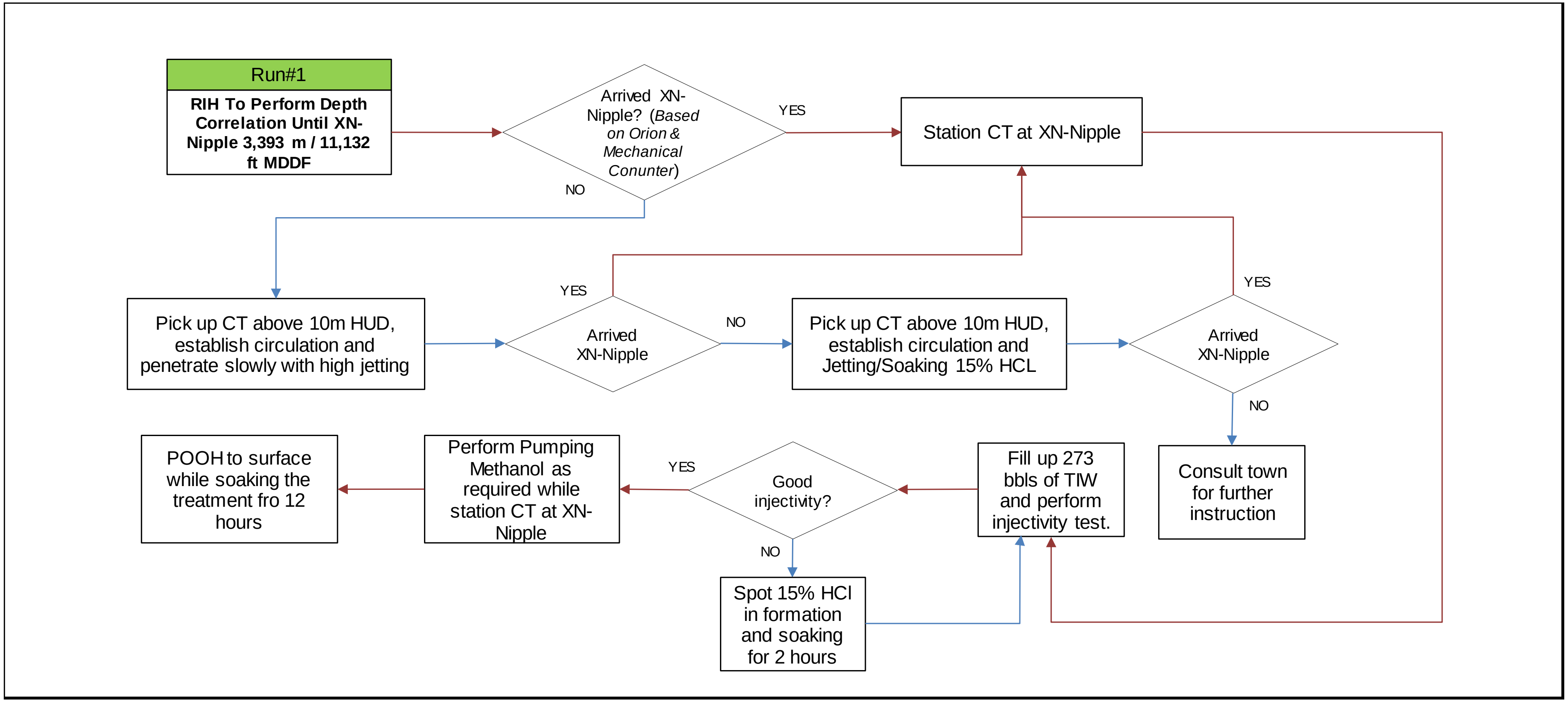


Precautionary Steps to avoid Stuck while Cleanout in Dual string Completion:

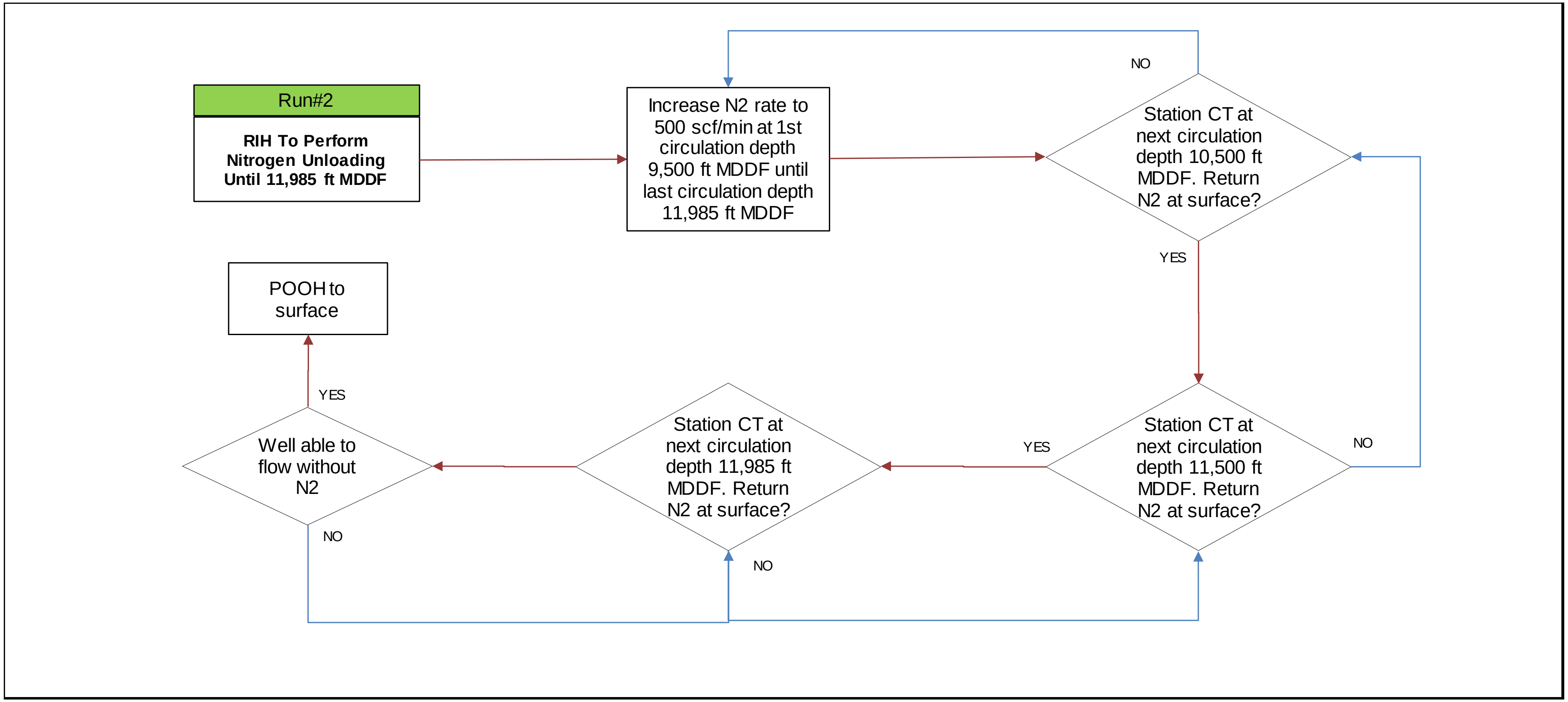
1) To monitor pressure trending all the times during operation and record for any abnormalities. If there is continue pressure increasing trend during cleanout, proceed to pick up coil to the previous pull test depth and perform flow rate test.
2) In the event of coil entangle on the Long string, proceed to pick up coil and simulate pumping lost prime scenario to create vibration and tip of coil wobble to release from entanglement.

APPENDIX V – DECISION TREE

- Run#1: Depth Correlation Decision Tree



- Run#2- Unloading Decision Tree



APPENDIX VI – PROJECT OPERATION TIMELINE

Dimension Bid Sdn Bhd

DIMENSION BID

Project Lead: Muhd Ameerul Zaeem
Project Start Date: 1/12/2022
Display Week: 1

Month	Job Description	Well No	Field	Start	End	Cal. Days
	Angsi A CTU Operation Timeline					
December	Skid CID and Jacking Frame	A-24L	Angsi A	1/12/2022	1/12/2022	1
December	Rig up CTU Equipment on Well A24L	A-24L	Angsi A	2/12/2022	4/12/2022	3
December	CTU Run#1: Depth Correlation & Methanol Soaking	A-24L	Angsi A	5/12/2022	6/12/2022	2
December	CTU Run#2: Nitrogen Unloading	A-24L	Angsi A	7/12/2022	8/12/2022	2
December	CTU Contingency Run: N2 Unloading	A-24L	Angsi A	9/12/2022	10/12/2022	2
December	Rig down CTU & Flowback equipment	A-24L	Angsi A	11/12/2022	13/12/2022	3
					Total Days:	13