DIMENSION BID

PETRONAS

ANGSI D-04S
SCALE CLEAN OUT & STIMULATION

Revision:	4
Prepared for:	Arsyamimi Bt Mohamed
Date Prepared:	22th August 2022
Well:	D-04S
Field:	Angsi
Operation Region:	PMA
Prepared by:	Muhammad Ameerul Zaeem
Phone:	+601129033294
Email:	ameerul@neudimension.com

DESIGN VERIFICATION

PREPARED BY DB CTS Field Engineer	 Muhammad Ameerul Zaeem	22/08/2022 Date
APPROVED BY DB CTS Operation Manager	 Aliff Amirul Adenan	22/08/2022 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.

DISTRIBUTION LIST

No	Personnel	Company	Name	Email
1	Well Intervention Engineer	PCSB	Arsyamimi Bt Mohamed	arsyamimi.mohamed@petronas.com.my
2	Well Service Supervisor (WSS)	PCSB	TBA	TBA
3	Offshore Installation Manager (OIM)	PCSB	TBA	TBA
4	Production Technologist	PCSB	Luqman Hakim Zulkafli	luqmanhakim.zulkaf@petronas.com
5	Cluster Head	PCSB	M Azza B Zaini	azzazaini@petronas.com
6	Head of well Intervention	PCSB	Eddy B Samaile	eddysamaile@petronas.com
7	Material Coordinator (Logistics)	DB – Kemaman	Marzokey	marzokey@neudimension.com
8	Service Supervisor	DB – Kemaman	TBA	TBA
9	Field Engineer Coiled Tubing Services	DB – Kemaman	Muhammad Ameerul Zaeem	ameerul@neudimension.com
10	Operation Engineer Coiled Tubing Services	DB – Kemaman	Mohammad Faizal Ali	faizal.ali@neudimension.com
11	Field Service Manager Coiled Tubing Services	DB – Kemaman	Mohd Khairul Ridhwan	khairul.ridhwan@neudimension.com
12	Operation Manager Coiled Tubing Services	DB – Kemaman	Aliff Amirul Adenan	aliff.adenan@neudimension.com
13	HSE Supervisor	DB – Kemaman	Ahmad	ahmad@neudimension.com

PERSONNEL CONTACT

Any means of following doubt / unusual parameters / Emergency, please contact Dimension Bid personnel in onshore immediately.

No	Name	Position	Company	Location	Contact No
1	Aliff Amirul Adenan	Operation Manager	DB	Kemaman	011 – 1225 7044
2	Mohd Khairul Ridhwan	Field Services Manager	DB	Kemaman	014 – 515 4452
3	Mohammad Faizal Ali	Operation Engineer	DB	Kemaman	013 – 736 1046

REVISION HISTORY

Rev. No	Section	Date	Revised By
0	All	7/08/2022	Muhd Ameerul Zaeem
1	To change BHA to SpinCat Nozzle in Run#1 and attached SISQ proposal from Baker Hughes	8/08/2022	Muhd Ameerul Zaeem
2	To change BHA to SpinCat Nozzle in Run#2 and include clean out analysis.	10/08/2022	Muhd Ameerul Zaeem
3	To incorporate comment as per NOWIP, include 2.25” Drift Ring in BHA in Run#2 and include milling BHA diagram.	15/08/2022	Muhd Ameerul Zaeem
4	To perform clean out starting at depth 500 m MDDF & change HUD based on latest TCC result on 19 Aug 2022.	22/08/2022	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 scale cleanout and acid stimulation on zone I-35U Southwest (1,992m – 2002.5 MDDF) on Angsi well D-04S.
2. To perform bullheading Scale Inhibitor Squeeze (SISQ) on I-35U zone.

BACKGROUND

Angsi D-04 is a dual string oil producer and was completed on August 2009. During Slickline TCC on 19th August 2022 with 2.72" LIB prior CTU operation on well D-04S, slickline has encountered HUD at 1,937m-WLTHF and fluid level was detected at 1,190m-WLTHF. Suspect impression of scale around LIB. PCSB has engaging with DB to perform scale cleanout and acid stimulation on zone I-35U reservoir.

WELL DATA

Input Parameter	Parameter Value
Field	Angsi-D04S
Max. Deviation (degrees)	40.8 degree @ 2,007m MDDF
Min. Restriction (inch)	**2.69" (XN Nipple) @ 1,968m MDDF (Short String)**
Tubing Specification	3-1/2" Production Tubing, 9.2# ppf
Type of Fluid & Density	9.1 PPG NaCl (based on Completion Fluid data in Well Diagram)
Top of Fluid	2,229ft MDDF / 1,998ft TVDDF
Current Well Status	Producing
Depth of zone	I-35U: 1,992m – 2,002.5m MDDF
Reservoir Pressure	2,173 psig
Reservoir Temperature	243 deg F
Porosity	28%
Permeability	N/A
Fracture Gradient	0.70psi/ft
Water cut	70%
Water Production Rate	1,600 bwpd
Mercury, HG	N/A
Additional Information / Notes / Special Requirement:	
• Latest HUD suspected scale detected at 1,937 m WLTHF (19 August 2022) • Fluid Level detected at 1,190 m WLTHF	

OPERATION SUMMARY

Item	*Job Description*	*Remark*
A	Slickline	1. To perform TCC until HUD
B	Coiled Tubing Operation	2. Run#1: SCO Using 1.69” SpinCat Nozzle Until EOT at 1,970-m MDDF 3. Run#2: Depth Correlation Using 1.69” SpinCat Nozzle c/w 2.75” FC Until XN-Nipple at 1,968-m MDDF / 6,457-ft MDDF and Stimulation
C	CT Contingency	4. Contingency #2: Milling Operation With 2.72” PDC Scale Mill Bit 5. Contingency #3: Well Unloading
D	Bullheading	6. Perform Tubing Pickling 7. Perform Pumping SISQ Treatment on Zone I-35U

WELL DIAGRAM

WELL NAME: ANGSI D4
LOCATION / SLOT: ANGSI D / 6

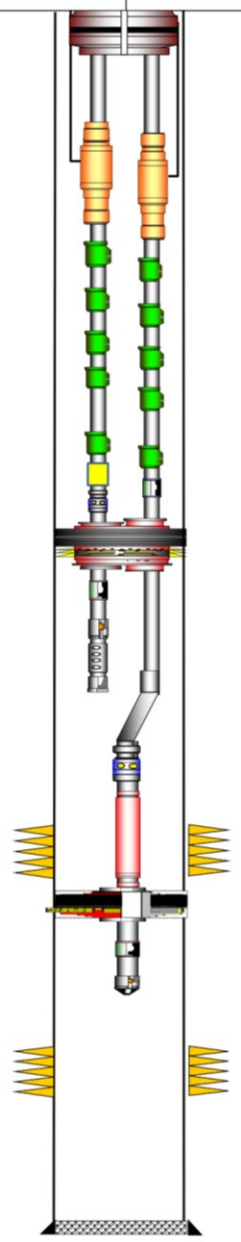
PROPOSED COMPLETION SCHEMATIC (DUAL STRING OIL PRODUCER)

DATE OF COMPLETION	:	Aug-09
RIG	:	T-10 (TADR)
TD	:	2090 m-MDDF
PBTD	:	2055 m-MDDF
MAXIMUM DEVIATION	:	40 deg
WATER DEPTH	:	68 m
DRILL FLOOR HEIGHT	:	33.89 m-AMSL
WELL HEAD	:	CAMERON
X-MAS TREE	:	CAMERON

Note: All depths are in meter from RKB to top of equipment.

		SIZE	WEIGHT	GRADE	THREAD	DEPTH
CONDUCTOR	:					
SURF. CASING	:					
INT. CASING	:					
CASING	:	9-5/8"	47 PPF	L-80	VAM TOP	990 m-MDD
LINER	:					
TUBING (LONG STRING)	:	3-1/2"	9.2 PPF	L-80	K-FOX	1007 m-MDD
TUBING (SHORT STRING)	:	3-1/2"	9.2 PPF	L-80	K-FOX	1975 m-MDD
COMPLETION FLUID	:	9.1 PPG NaCl (DRILL WATER + NaCl + 3% KCl) filtered to 30 NTU				
PACKER FLUID	:	9.1 PPG (3% NaCl + 0.2% BIOCIDE + 2% OXYGEN SCAVANGER + 2% CORROSION INHIBITOR)				

SHORT STRING (OIL PRODUCER)			Deviation Degree	DEPTH m-MDDF
MAX OD IN	MIN ID IN	EQUIPMENT		
3.920	2.880	FLOW COUPLING		
5.030	2.813	SCSSV-TRSV (Self Equalizing)		271
3.920	2.880	FLOW COUPLING		
5.360	2.867	SPM #1 DUMMY AUG 2021		567
5.360	2.867	SPM #2 DUMMY AUG 2021		749
5.360	2.867	SPM #3 (GLOV: 12/64")		873
5.360	2.867	SPM #4 (dummy)		1197
		PIP TAG #1		1807
		PIP TAG #2		1819
5.360	2.867	SPM #5 (dummy)		1838
4.000	2.992	RA SUB		1937
3.893	2.813	SLIDING SLEEVE DOOR CLOSED	40	1956
3.893	2.690	XN-NIPPLE (2.75")	40	1968
3.920	3.000	POP ASSEMBLY		1969
		PERFORATED PUP		
		CATCHER SUB		1970
		EOT		
			40	
I-35U OIL PRODUCER 1992 - 2002.5 MDDF (10.5m) 2300 psi/233 deg F 1599 m TVD SS				
			40	
		Sand Interval Difference : 5.5 m		
			40	
I-35 L OIL PRODUCER 2008 - 2014 MDDF (6m) 2300 psi/236 deg F 1663 m TVD SS				
		PBTD at 2055 m-MDDF -5/8" Float Collar at 2055m-MDDF /8" Casing Shoe at 2085 m-MDDF		

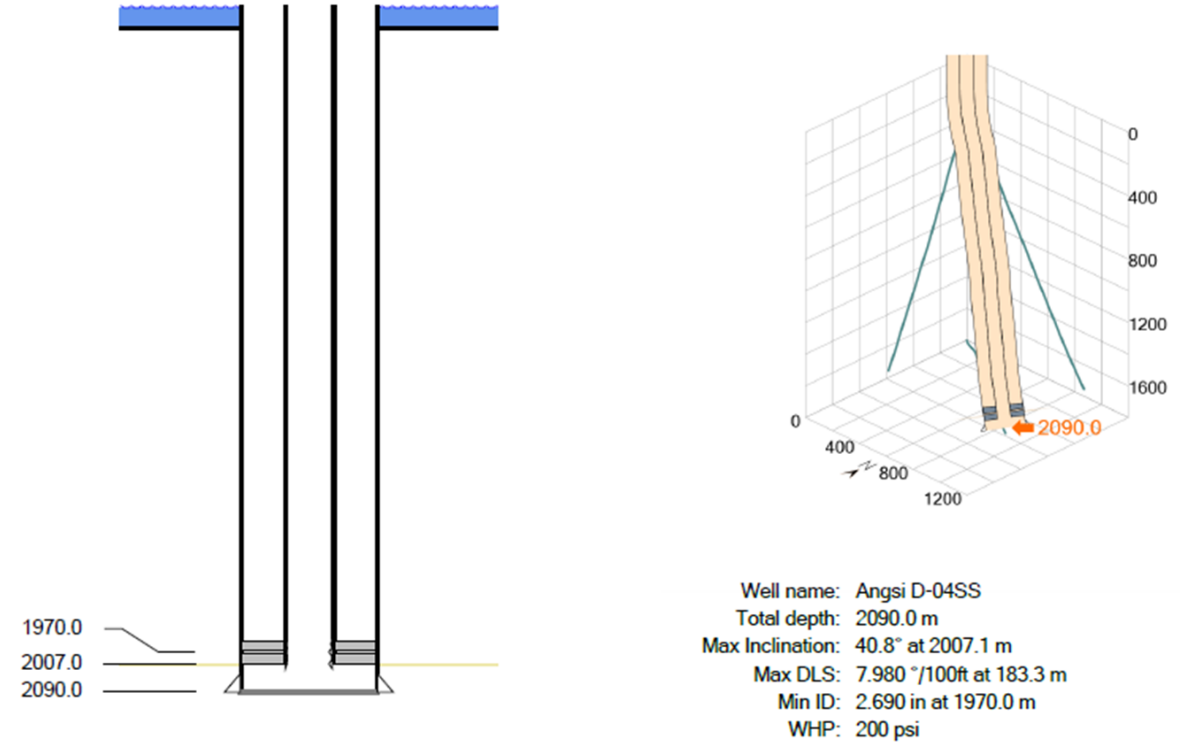


TD at 2090 m-MDDF

DEPTH m-MDDF	LONG STRING (OIL PRODUCER) EQUIPMENT	MIN ID IN	MAX OD IN
	FLOW COUPLING	2.880	3.920
280	SCSSV-TRSV (Self Equalizing)	2.813	5.030
	FLOW COUPLING	2.880	3.920
576	SPM #1 (dummy)	2.867	5.360
768	SPM #2 (dummy)	2.867	5.360
892	SPM #3 (GLOV: 12/64")	2.867	5.360
1207	SPM #4 (dummy)	2.867	5.360
1847	SPM #5 (dummy)	2.867	5.360
1946	X-NIPPLE	2.813	4.550
1965	9-5/8" X 3-1/2" BHD PACKER (72 klbs pull on L/S to release)	2.880	8.230
1976	SLIDING SLEEVE DOOR CLOSED	2.813	3.893
	BLAST JOINT ± 5 METERS TOP AND BOTTOM	2.880	3.900
2001	leak identified HPT-SNL March 2017		
2004	9-5/8X 3-1/2" BHR PACKER	2.940	6.000
2005	Packer is holding		
2006	XN-NIPPLE (2.75") set plug April 2017	2.690	3.893
2007	POP ASSEMBLY	3.000	3.920
	EOT		
2014	Behind casing cross flow HPT-SNL Mar		
2025			
2085	9-5/8" CSG SHOE		

Update by: Sean Syazrul
Date: 7-May-13

WELL 3D PLOT



Input Parameter	*Parameter Value*
Field	ANGSI ANDRA
Trajectory Until Depth	2,090m MDDF (TD)
Max. Deviation (degrees)	40.08 degree at 2,007.1m MDDF
Min. Restriction (inch)	2.69” @ 1,968m MDDF

TREATMENT VOLUME

Description	Details
Tubing Specification	3-1/2", 9.2#, L-80
Prod. Casing Specification	9-5/8", 47#, L-80

Angsi D04S **Downhole Calculation** **Prepared Date: 03-08-22**

Tubing

Type	External Pipe			Internal Pipe			Internal Pipe			Caps	From	To	From	To	Length	Total 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	33.89	1956.00	111	6418	6306	54.8
SSD#1 to EOT	3 1/2	2.992	9.2							0.00870	1956.00	1970.00	6418	6464	46	0.4
															TOTAL	55.2

A-Annulus (PCP)

Type	External Pipe			Internal Pipe			Internal Pipe			Caps	From	To	From	To	Length	Total 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	8.681	47	3 1/2	2.992	9.2	3 1/2	2.992	9.2	0.04941	33.89	1965.00	111	6447	6336	313

Wellbore Area on I-35U Reservoir

Type	External Pipe			Internal Pipe			Internal Pipe			Caps	From	To	From	To	Length	Total 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	9 5/8	8.681	47	3 1/2	2.992	9.2	3 1/2	2.992	9.2	0.04941	1965.00	1970.00	6447	6464	16	0.8
EOT to I-35U Top Perf	9 5/8	8.681	47	3 1/2	2.992	9.2				0.06130	1970.00	1992.00	6464	6536	72	4.4
I-35U Top Perf to I-35U Bottom Perf	9 5/8	8.681	47	3 1/2	2.992	9.2				0.06130	1992.00	2002.50	6536	6570	34	2.1
I-35U Bottom Perf to Packer#2	9 5/8	8.681	47	3 1/2	2.992	9.2				0.06130	2002.50	2004.00	6570	6575	5	0.3
															TOTAL	7.6

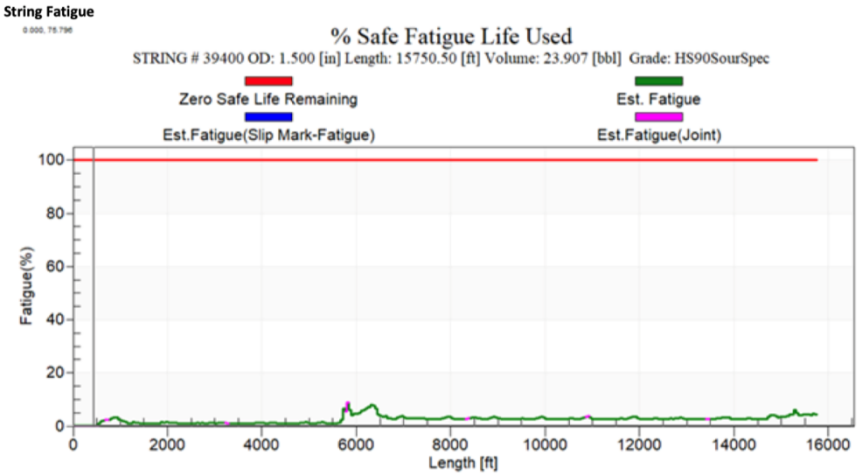
3ft Penetration - Zone I-35U Reservoir

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-35U Reservoir		81.625		9 5/8			36	6.38210	1992.00	2002.50	6536	6570	34	220
													Porosity	0.28
													Total	61.6
												Total Treatment Volume		69.2
												30% excess to cover leakage to I-35L		90.0

COILED TUBING STRING INFORMATION

OD (in)	Spec	W/T (in)	ID (in)	Length (ft)
1.5	Tenaris	0.125	1.25	15,503
CT Volume: 23.5 bbls				

CT STRING FATIGUE



CT STRING #HS39400 LATEST PIPE MANAGEMENT

Run	Date	Client	Field	Well	Job	Running ft	Cum. Run	Max CTW	Max CTP	New CT leng	Cum Running in Chrome	Job Fatigue	Job Corrosion	Max Fatigue	Cum. Corrosion	Used String Life
#		Name	Name	Num	type	ft	ft	lb	psi	ft	ft	%	%		%	%
1	02-01-21					NA	NA	NA	NA	15,799	NR					
2	05-Jan-21			A13L	CT MECHANICAL	NR	NR	NR	NR	15,789	NR					
3	05-Feb-21			A13L	CT MECHANICAL	NR	NR	NR	NR	15,788	NR					
4	02-Apr-21			A16L	CT MECHANICAL	NR	NR	NR	NR	15,786	NR					
5	06-Sep-21			A5U	CT WELL CLEANOUT	NR	NR	NR	NR	15,784	NR					
6	27-Oct-21					NR	NR	NR	NR	15,775	NR					
7	02-Nov-21			A16L	FISHING	NR	NR	NR	NR	15,770	NR					
8	02-Nov-21			A16L	CT FILL/SCP	NR	NR	NR	NR	15,770	NR					
9	02-Nov-21			A16L	FISHING	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	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	15,713	9283	1.65	0.5	10.52	12.5	23.02
12	01-Jul-22	PCSB	DULANG	A-4L	RUN#2 CLOSE SSD USING 2.813" KEY SHIFTING TOOL	8764	18047	NA	NA	15,713	18047	1.63	0.5	11.87	13	24.87
13	03-Jul-22	PCSB	DULANG	A-4L	RUN#3 DRIFT RUN UNTIL SSD#3	11404	29451	NA	NA	15,703	29451	1.68	0.5	12.15	13.5	25.65
14	04-Jul-22	PCSB	DULANG	A-4L	RUN#4 DEPTH CORRELATION WITH GRCCL	11284	40735	NA	NA	15,703	40735	0.1	0.5	12.15	14	26.15
15	05-Jul-22	PCSB	DULANG	A-4L	RUN#5 SET BRIDGE PLUG	10,888	51623	NA	NA	15,703	51623	0.5	0.5	12.43	14.5	26.93
16	07-Jul-22	PCSB	DULANG	A-4L	RUN#6 WLD BASE LINE	10887	62510	NA	NA	15,603	62510	0.49	0.5	12.7	15	27.7
17	09-Jul-22	PCSB	DULANG	A-4L	RUN#7 WLD ACTIVE LEAK PASS	13339	75849	NA	NA	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	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	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	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	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	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	15,503	131,427	1.74	0.3	15.51	18	33.51

Based on above pipe management;

- Current CT Fatigue Life is 15.51%
- Current String Used Life is 33.51%
- Current Running Footage in Chrome Completion is **131,427ft**
- Current Total Running Footage is 131,427ft

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

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

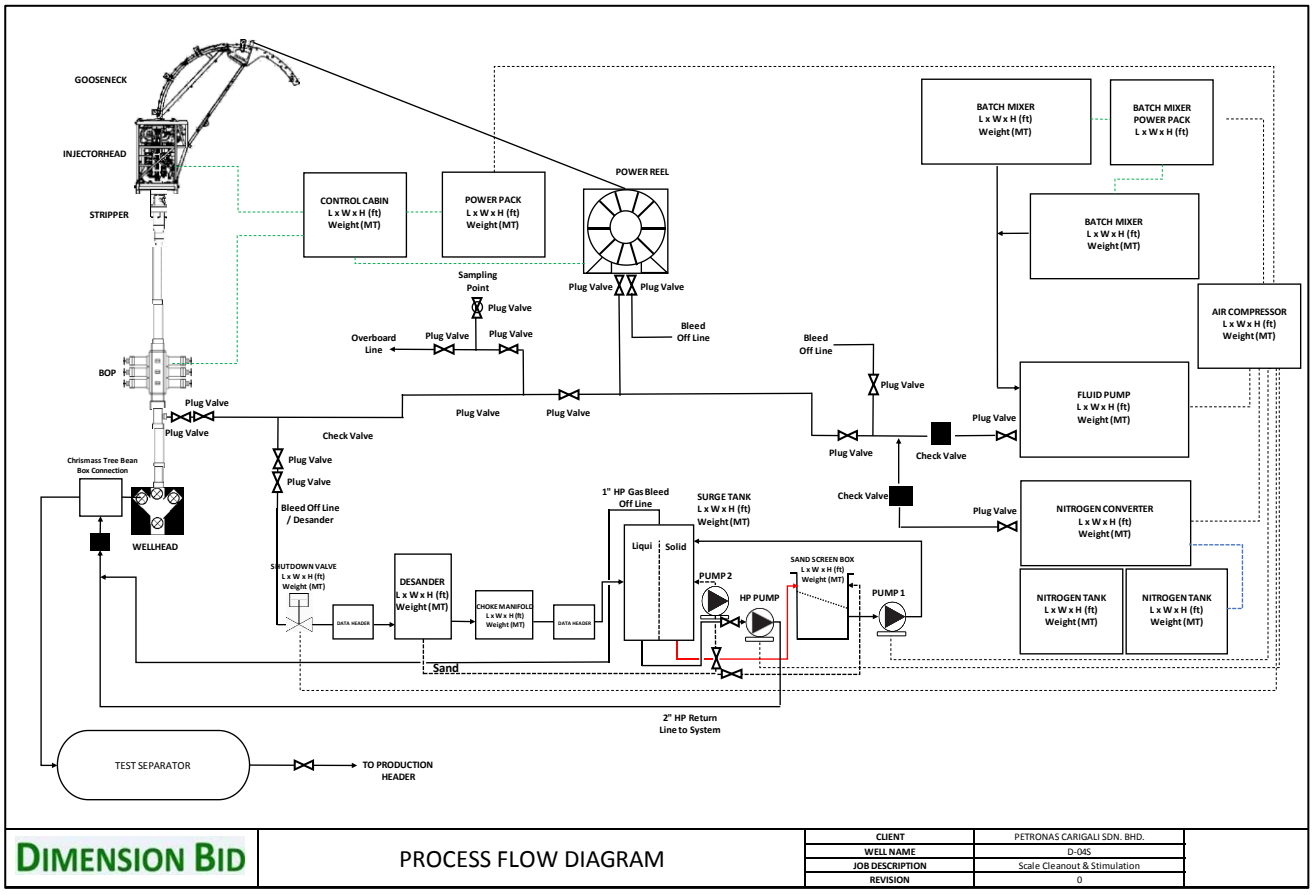
Based on Dimension Bid Standard Operating Procedure (SOP) of Pipe Management to junk the coil;

- **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	Mid Perf, TVD, ft	Hyd. Pressure, psi	Fracture Pressure, psi	STP, psi	80% MASTP, psi
Treated Fresh Water	8.46	5,537	2,436	3,876	1,440	1,100
Treated Injection Water	8.62	5,537	2,481	3,876	1,394	1,100
PFA 200	8.87	5,537	2,554	3,876	1,322	1,100
Pre-Flush Solvent	8.46	5,537	2,436	3,876	1,440	1,100
15% HCl	8.80	5,537	2,534	3,876	1,342	1,100
Flush Solvent	8.46	5,537	2,436	3,876	1,440	1,100
SISQ	8.64	5,537	2,487	3,876	1,388	1,100

PROCESS FLOW DIAGRAM



DIMENSION BID	PROCESS FLOW DIAGRAM		
		CLIENT	PETRONAS CARIGALI SDN. BHD.
		WELL NAME	D-04S
		JOB DESCRIPTION	Scale Cleanout & Stimulation
		REVISION	0

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 (34,300 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:

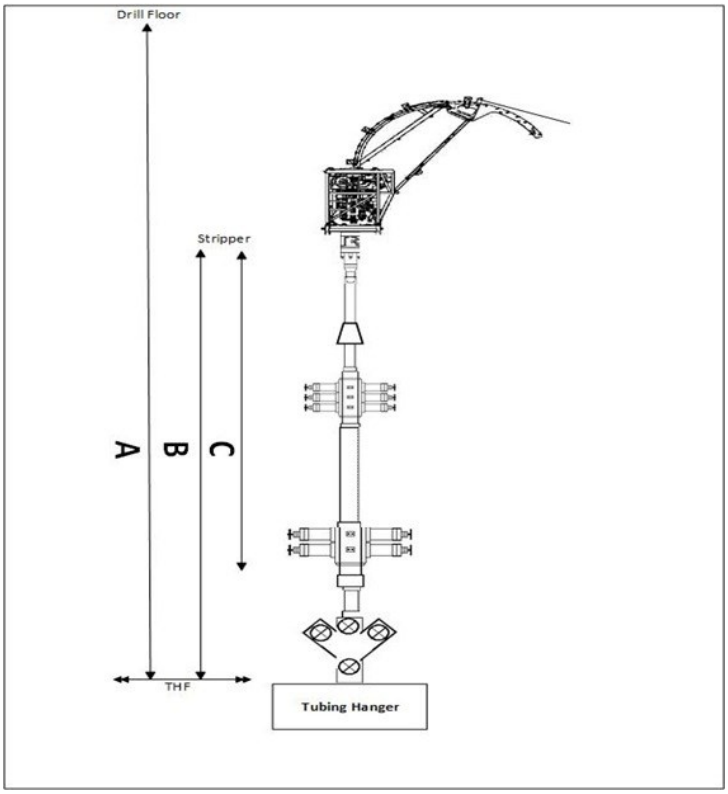
19.1. For low pressure:

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:

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:

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

   5.2. 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

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 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 D-04S 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

Depth Interval (MDDF)	Deviation Range (deg)
459 – 2090	30 - 40

.

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 14.9-m as per tubing tally)

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 (SHORT STRING) – RUN#1 SCO USING 1.69" SPINCAT NOZZLE UNTIL EOT AT 1,970 M MDDF

All depths specified below are in m-MDDF (Drill floor to THF is 14.9-m as per tubing tally)

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

1. Prior to start CT operation, record initial well pressure parameter & perform pre-treatment by collect well fluid sample before shut in well and record pH & water cut. This will be reference during flowback after finish soaking period during CT Run#2.

   1.1. Collect sample prior shut in well. Label the sample bottle with type of sample, name of well, date and time the sample was collected.

Sample	Volume	pH Reading	Water Cut, %
Produced Fluid	1,000 mL		

   1.2. Record initial SITHP of short string and long string and PCP of well D-04S.

SITHP Short String	SITHP Long String	PCP

   1.3. Bleed off PCP to minimum as possible or 200 psi. Ensure the FCV is isolate properly. Continuously monitor PCP & record in daily report from time to time during operation.

2. 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.

3. 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 injection 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.

4. Rig up coiled tubing unit and surface line on Angsi-D platform as per Site Visit Report:

   4.1. Review JHA and risk assessment with all personnel involve in the rig up operation. Please send a copy of JHA to Engineer in Charge.

   4.2. Lift up coiled tubing unit using crane and spot on platform.

   4.3. Rig up Coiled Tubing package and surface treating line.

   4.4. Rig up 2" kill line to BOP kill port.

   4.5. Rig up 2" flexible hose from pumping tee.

   4.6. Pig coil tubing with treated sea water to ensure no debris is inside coil. **Record coil tubing volume in treatment report.**

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

   4.8. Install the Pull and Pressure Test Sub.

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

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

   4.10. 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.

      4.10.1. 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.

      4.10.2. 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.

5. Make up 1.69" SpinCat Nozzle tool as per **BHA#1: 1.69" SpinCat Nozzle** in **Appendix 1**.

6. Perform function test of the SpinCat Nozzle to determine at which pump rate and pressure of the tool start to rotate / operate. Record the data in the table below, do not exceed 5,000psi. Recommended flowrate is 0.7 bpm to 1.3 bpm.

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		
1.4		

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

8. Make up the Injector Head and Stripper to the stack up.
9. 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.
   9.1. 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.

   9.2. 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.
10. 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.
    10.1. 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 9.2 and 10.
11. Upon successful test, bleed off the pressure in the coiled tubing stack up to zero through the pump-in sub.
12. Zero both depth counters at reference point.
13. Confirm all wellhead and BOP valves are in open position via physical check.
    13.1. Prior to opening the wellhead valve pressure up above master valves to a pressure equal to the expected shut-in wellhead pressure.
    13.2. Count wellhead valves turns while opening and record it the treatment report for reference in future.
    13.3. Manipulate surface valve to the following position:

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

14. Start running in hole coil tubing to **500 m / 1,629 ft MDDF** while pumping **Treated Injection Water** at minimum rate permissible.
    14.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix III.
    14.2. 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 treatment report.
    14.3. Maximum coil speed running in hole is **30-50 ft/min.**
    14.4. Slow down coil speed to **10 ft/min**, 50 ft before and after passing through completion accessories.
    14.5. Closely observe weight indicator in control cabin while running in hole.
    14.6. Observe return all the times.

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

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

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

14.10. 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.

15. Once CT reach 500-m MDDF, continue RIH while pumping at high jetting rate at 1.0 bpm starting at depth **500-m MDDF until EOT, 1,970-m MDDF** (suspect scale built up on tubing based on MIT April 2022).

16. Once CT reach **1,927 m MDDF / 6,322 ft MDDF (10 m above previous HUD),** 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*

17. If CT encounter HUD **(previous HUD at 1937m WLTHF), flag CT on surface** and record in report as our reference point, pick up CT back to 10m above HUD. Increase pump rate to maximum pump rate achievable (with reference to pump rate in step 6) to start penetrate the HUD. Continue circulating until good return establish at surface. (Proceed to steps 20 if CT did not encounter any HUD)

Note: Pump rate can be increase to max 1.3bpm or until reach maximum circulating pressure of 5,000 psi.

17.1. Once good return observed at surface, continue to penetrate into HUD with 10ft/min CT speed. Circulate 5bbls of D801 gel after each penetration of 30m bite

17.2. **IF** no return is observed on surface, continue to fill up tubing with **83 bbls** (1.5 Tubing Volume) of TIW. Monitor pressure on CHP if there are any build ups and fluid return observe on tubing and casing (Tubing communicate with A-Annulus).

17.2.1. **IF** no pressure built up in CHP and returns established at surface while pumping 83 bbls of TIW, proceed with Step 17.4.

17.2.2. **IF** no constant return is observed on surface after exceeding 83 bbls of TIW with a pressure build up on CHP, continue fill up until return observe on PCP and return establish at tubing.

17.3. **IF** no constant return is observed on surface, introduce nitrogen at pumping rate (350 – 400 scf/min).

17.3.1. Monitor THP and well condition while establishing return.

17.3.2. Upon establishing constant return, proceed with penetrate the HUD.

Note: Monitor weight during penetration. If no weight loss more than 500lbs observes during penetration, continue penetrate HUD. Maximum cleanout penetration is 30m.

Perform wiper trip for every 30m interval cleanout (from cleanout depth until initial depth) while pumping 5bbls of D801 Gel.

17.4. Continue penetrate HUD as per below table until **1,970 m / 6,464ft MDDF (EOT)**.

No.	Stage	Fluid	Liquid Rate	Total Liquid	N2 Rate (if require)	CT Speed	Duration	Depth	Remarks
			BPM	BBL	SCF/M	ft/min	Minute	m	
1	CT at 10m above HUD	TSW	1.0	0.0	300	0	0	10m above HUD	Establish return on surface
2	RIH to HUD and Penetrate HUD/Fill	TSW	1.0	10.0	300	10	10	HUD + 30m	Monitor return & CT weight on surface
3	Circulate	D801 Gel	1.0	5.0	300	0	5	Stationary CT	Provide suspension to the fill and lift to surface
Pull Test 10m									
4	RIH to last HUD and Penetrate HUD/Fill	TSW	1.0	10.0	300	10	10	HUD + 30m	Monitor return & CT weight on surface
5	Circulate	D801 Gel	1.0	5.0	300	0	5	Stationary CT	Provide suspension to the fill and lift to surface
Pull Test 10m									
Repeat above step 1 to 4 until reached EOT@1,970m-MDDF									
7	Hole Cleaning (Circulate)	D801 Gel	1.0	41.5	300	0	42	Stationary CT @ EOT at 1,970m MDDF	Hole cleaning stage. 1.0x CT/Tubing Annulus Volume
8	Bottoms Up (Circulate)	TSW	1.0	83	300	0	83	Stationary CT @ EOT at 1,970m MDDF	Hole Cleaning stage. 2.0x CT/Tubing Annulus volume.
Once completed CBU and clear return is established, POOH to surface									
9	POOH	TSW	0.3	41.5	300	30	216	To Surface	Monitor return on surface

18. Once CT reach at EOT depth at **1,970 m / 6,464ft MDDF**, proceed hole cleaning by pump 1x annulus volume of gel (**41.5 bbls)** and follow by bottoms up with TIW **83 bbls** (2x annulus volume).
19. If CT encountered hard obstruction, proceed to pick up CT 10m above the obstruction and circulate at least 2x bottom up with nitrified TIW until clear return is observe on surface before proceed with the following steps.
    19.1. RIH and slack off CT not exceeding 1000 lbf on top of the obstruction and attempt to jet on the obstruction. If no success proceeds to mix **10 bbls of 15% HCl acid and Neutralization Fluid** as per the following recipe:

15% HCl (Main Treatment)				10	BBL	Description
Seq.	Product	Concentration		Volume		
1	Fresh Water	419	gptg	176	gals	Base Fluid
2	ACM CORR 400	4	gptg	2	gals	Acid Corrosion Inhibitor
3	MESB NE 200	4	gptg	2	gals	Non-Emulsifier
4	ACM Surf 210	3	gptg	1	gals	Surfactant
5	Ammonium Chloride	417	pptg	175	lbs	Clay Stabilizer
6	ACM Iron 300	25	pptg	11	lbs	Iron Sequestering
7	ACM Iron 200	15	gptg	6	gals	Iron Control
8	33% HCl	419	gptg	176	gals	Raw Acid
9	MESB MS 300	100	gptg	42	gals	Mutual Solvent

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

Neutralization Fluid				10	BBL	Description
Seq.	Product	Concentration		Volume		
1	Injection Water	976	Gptg	410	gal	Base fluid
2	Soda Ash	500	pptg	210	lbs	Neutralization fluid

Mixing Instruction:
1. Prepare injection water in the mixing tank.
2. Mix soda ash into tank and agitate until mixture is homogenous.

19.2. Upon completion mixing 15% HCl acid, proceed to jet 5 bbls of 15% HCl on top of the obstruction while attempt to pass through the obstruction. If no progress consult town prior moving to next step.

19.3. If no success during jetting HCl acid, proceed to spot another 5 bbls of 15% HCl on top of obstruction and pick up CT at least **550m** above the obstruction depth to soak the acid for 2 hours. After completed soaking, proceed to RIH to pass through the obstruction while pumping nitrified TIW. If unable to penetrate consult town, tag HUD, flag coil and POOH to surface (prepare to POOH to change BHA to Milling as per stated in Contingency #1)

19.4. During circulation, if acid return observes on surface return line, inject soda ash using chemical injection pump on the surface return line to neutralize the acid.

20. At **1,960 m / 6,431 ft MDDF (10m above EOT)**, stop coil and 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

21. Continue RIH slowly at 5ft/min with pumping rate 0.3BPM until EOT at **1,970 m / 6,464ft MDDF**. Once completed CBU and observed clear return is established.

22. Upon completed bottoms up, pickup CT to XN-Nipple at 1,968m / 6,457ft MDDF and flag CT at surface as Flag#1.

Flag Number	*Colour*
Flag#1	

23. After completed flag, **POOH** CT to SPM#5 depth at **1,838-m MDDF**, increase pump rate to 1.0 bpm or without exceeding circulating pressure of 5,000 psi. Continue **jetting across SPM until depth at 500-m MDDF**. Repeat for **three passes** at 1.0 bpm. Keep monitor return at surface.
24. POOH CT to surface while pumping TIW at 0.3bpm. Ensure continuous return on surface is observed.
    24.1. Maximum coil speed while POOH is 50ft/min.
    24.2. Slow down coil speed to 10ft/min 50ft before and after passing through completion accessories.
25. Once CT on surface, close well and bleed off pressure in coil and stack up.
26. Ensure to collect sample at DPSF and send to town for analysis.

COILED TUBING OPERATION (LONG STRING) – RUN#2 DEPTH CORRELATION USING 1.69" SPINCAT NOZZLE C/W 2.75" FC UNTIL XN-NIPPLE AT 1,968m / 6,457ft MDDF AND STIMULATION

All depths specified below are in m-MDDF (Drill floor to THF is 14.9-m as per tubing tally)

27. Make up 1.69" SpinCat Nozzle tool as per **BHA#2: 1.69" SpinCat Nozzle c/w 2.75" FC** in **Appendix I**.
28. Record initial SITHP of short string and long string and PCP of well D-04S. Compare pressure parameter record in Run#1 and inform town if there any changes.

SITHP Short String	SITHP Long String	PCP

29. Perform function test of the SpinCat Nozzle to determine at which pump rate and pressure of the tool start rotate / operate. 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		
1.4		

30. Repeat step 7 till 13 in Run#1 prior opening the well.

31. Start running in hole coil tubing to **1,968m / 6,457ft MDDF (XN-Nipple)** while pumping **TIW** at minimum rate permissible.
    - 31.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix III.
    - 31.2. 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 treatment report.
    - 31.3. Maximum coil speed running in hole is **30-50 ft/min.**
    - 31.4. Slow down coil speed to **10 ft/min**, 50 ft before and after passing through completion accessories.
    - 31.5. Closely observe weight indicator in control cabin while running in hole.
    - 31.6. Observe return all the times.
    - 31.7. Regularly inform WSS on job status at all times.
    - 31.8. Do not exceed operating safety limits **5,000 psi.**
    - 31.9. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
    - 31.10. 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.
32. If CT encounter HUD, pick up CT back to 30m above HUD. Increase pump rate to maximum pump rate achievable (with reference to pump rate in Step 29) to start penetrate the HUD. Continue circulating until good return establish at surface. (Proceed to steps 35 if CT did not encounter any HUD)

    Note: Pump rate can be increase to max 1.3bpm or until reach maximum circulating pressure of 5,000 psi.
    - 32.1. Once good return observed at surface, continue to penetrate into HUD with 10ft/min CT speed. Circulate 5bbls of D801 gel after each penetration of 30m bite
    - 32.2. **IF** no return is observed on surface, continue to fill up tubing with 83 bbls (1.5 Tubing Volume) of TIW. Monitor pressure on CHP it there are any build ups and fluid return observe on tubing and casing (Tubing communicate with A-Annulus).
        - 32.2.1. **IF** no pressure built up in CHP and returns established at surface while pumping 83 bbls of TIW, proceed with Step 32.4.
        - 32.2.2. **IF** no constant return is observed on surface after exceeding 83 bbs of TIW with a pressure build up on CHP, continue fill up until return observe on PCP and return establish at tubing.
    - 32.3. **IF** no constant return is observed on surface, introduce nitrogen at pumping rate (350 – 400 scf/min).
        - 32.3.1. Monitor THP and well condition while establishing return.
        - 32.3.2. Upon establishing constant return, proceed with penetrate the HUD.

        Note: Monitor weight during penetration. If no weight loss more than 500lbs observes during penetration, continue penetration sand. Maximum cleanout penetration is 30m.

        Perform wiper trip for every 30m interval cleanout (from cleanout depth until initial depth) while pumping 5bbls of D801 Gel.
    - 32.4. Continue penetrate HUD as per below table until **1,968.00m/6,457ft MDDF (XN-NIPPLE)**.

No.	Stage	Fluid	Liquid Rate	Total Liquid	N2 Rate (if require)	CT Speed	Duration	Depth	Remarks
			BPM	Bbl	SCF/M	ft/min	Minute	m	
1	CT at 30m above HUD	TIW	1.0	0.0	350	0	0	30m above HUD	Establish return on surface
2	Penetrating HUD/Fill	TIW	1.0	10.0	350	10	10	HUD + 30m	Monitor return & CT weight on surface
3	Circulate	D801 Gel	1.0	5.0	350	0	5	Stationary CT	Provide suspension to the fill and lift to surface
Pull Test 10m									
4	RIH to HUD and Penetrate HUD/Fill	TIW	1.0	10.0	350	10	10	HUD + 30m	Monitor return & CT weight on surface
5	Circulate	D801 Gel	1.0	10.0	350	0	10	Stationary CT	Provide suspension to the fill and lift to surface
Pull Test 10m									
Repeat steps until reach XN-Nipple at 1,968.00m/6,457ft MDDF									

33. If CT encountered hard obstruction, proceed to pick up CT 10m above the obstruction and circulate at least 2x bottom up with nitrified TIW until clear return is observe on surface before proceed with the following steps.

    33.1. RIH and slack off CT not exceeding 1000 lbf on top of the obstruction and attempt to jet on the obstruction. If no success proceeds to mix **10 bbls of 15% HCl acid and Neutralization Fluid** as per the following recipe:

15% HCl (Main Treatment)				**10**	***BBL***	***Description***
Seq.	***Product***	***Concentration***		***Volume***		
1	Fresh Water	419	gptg	176	gals	Base Fluid
2	ACM CORR 400	4	gptg	2	gals	Acid Corrosion Inhibitor
3	MESB NE 200	4	gptg	2	gals	Non-Emulsifier
4	ACM Surf 210	3	gptg	1	gals	Surfactant
5	Ammonium Chloride	417	pptg	175	lbs	Clay Stabilizer
6	ACM Iron 300	25	pptg	11	lbs	Iron Sequestering
7	ACM Iron 200	15	gptg	6	gals	Iron Control
8	33% HCl	419	gptg	176	gals	Raw Acid
9	MESB MS 300	100	gptg	42	gals	Mutual Solvent

Mixing Instruction:

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

Neutralization Fluid				10	BBL	Description
Seq.	Product	Concentration		Volume		
1	Injection Water	976	Gptg	410	gal	Base fluid
2	Soda Ash	500	pptg	210	lbs	Neutralization fluid

Mixing Instruction:

1. Prepare injection water in the mixing tank.
2. Mix soda ash into tank and agitate until mixture is homogenous.

33.2. Upon completion mixing 15% HCl acid, proceed to jet 5 bbls of 15% HCl on top of the obstruction while attempt to pass through the obstruction. If no progress consult town prior moving to next step.

33.3. If no success during jetting HCl acid, proceed to spot another 5 bbls of 15% HCl on top of obstruction and pick up CT at least **550m** above the obstruction depth to soak the acid for 2 hours. After completed soaking, proceed to RIH to pass through the obstruction while pumping nitrified TIW. If no success consults town prior for way forward.

33.4. During circulation, if acid return observes on surface return line, inject soda ash using chemical injection pump on the surface return line to neutralize the acid.

34. If no success after attempt to perform high jetting with TIW, high jetting with 15% HCl and 15% HCl acid soaking, tag the HUD depth and flag the coil on surface and POOH CT to surface and proceed with milling operation as stated in **Contingency #1**.

35. At **1,958.00m/6,424 ft MDDF (10m above XN Nipple)**, stop coil and 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*

36. Continue RIH slowly at 5ft/min with pumping rate 0.3BPM until XN Nipple at 1**,968.00m/6,457ft MDDF**.

36.1. If unable to reach XN Nipple at 1,968.00m/6,457ft MDDF after attempt to perform high jetting with TIW, high jetting with 15% HCl and 15% HCl acid soaking**,** consult WSS / town to decide whether to proceed with **step 39** (Stimulation).

37. Once completed pull test, slow down coil speed to 10ft/min and continue RIH to tag XN Nipple Profile at 1,968m / 6,457ft MDDF while pumping at minimum permissible rate, 0.3 bpm. (Do Not Slack Off More Than 1,000 lbf). Fluted Centralizer OD 2.75" will act as stopper at the XN Profile.

Flag Number	*Colour*
Flag#2	

38. Once HUD is tagged, pick up CT to 1,958m / 6,457ft MDDF, (10m above XN Nipple), and continue to RIH to re-tag No GO to verify the depth, flagged coil as Flag#2. (Do Not Slack Off More Than 1,000 lbf).

39. With the coiled tubing station at the XN Profile (Flag #2), proceed to mix the following **TFW** solution for Injectivity Test.

40. Prepare 179 bbls (1.5x completion volume of short string including long string) 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	4,028	gals	95.90	bbls	Base Fluid
MESB NE-Surf 200	2	gptg	8	gals	0.20	bbls	Non-Emulsifier Surfactant
Ammonium Chloride	417	pptg	1,751	lbs			Clay Stabilizer
ACM Oxyfree 100	2	gptg	8	gals	0.20	bbls	Oxygen Scavenger
ACM H2SClear 200	2	gptg	8	gals	0.20	bbls	CO2 & H2S Corrosion Inhibitor
ACM Bact 200	2	gptg	8	gals	0.20	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.

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

SITHP (psi)	CHP (psi)

42. Bleed off tubing and casing pressure to 0 psi or to minimum as possible.
43. Once complete above step, proceed to fill up the completion volume with 179 bbls (1.5x completion volume) TFW or till steady return is observe on surface without any Nitrogen injection, whichever comes first.
    - 43.1. Do not exceed 5,000 psi CT Circulation pressure or 1,100 psi THP/WHP during pumping activity. Whichever comes first.
    - 43.2. If THP/WHP exceed 1,100 psi during pumping, stop pump and bleed off pressure prior re-attempt the Injectivity Test.
    - 43.3. Consult town in the event the pumping pressure still above 1,100 psi after re-attempt.
    - 43.4. Ensure that one personnel are on standby at fluid storage tank during pumping to monitor fluid level.
    - 43.5. 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 SS (psi)	THP LS (psi)	CHP (psi)	Remark

44. Proceed with pump TFW to fill up completion volume (**179 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**	179 bbls or till return is observed on surface without N2 Injection	0.3-1.4	179 bbls is calculated based on 1.5x completion volume (SS, LS & Wellbore)	1,100

45. Once the 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

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

Rate (bpm)	Pumping Pressure (psi)	Time (min)	Volume (bbls)	THP SS (psi)	THP LS (psi)	CHP (psi)
0.30						
0.40						
0.50						
0.60						
0.70						
0.80						
0.90						
1.00						
1.10						
1.20						
1.30						
1.40						

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

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

46.3. DO NOT exceed MASTP/WHP of 1,100 psi.

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

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

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

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

48. **Continue pump TFW** with idle rate and monitor return while preparing all required treatment fluid.
49. Report the injectivity test result to EIC and WSS.
50. Once obtain approval from DB EIC and PCSB EIC to proceed with the stimulation operation, prepare main treatment fluid as per below recipe:

Pre-Flush Solvent				3990	gals	95	bbls	Description
Seq	Product	Concentration		Volume				
1	Fresh Water	863	gptg	3,443	gals	82.0	bbls	Base Fluid
2	MESB NE-Surf 200	4	gptg	16	gals	0.4	bbls	Non-Emulsifier Surfactant
3	NH4Cl Powder	417	pptg	1,664	lbs			Clay Stabilizer
4	MESB MS 300	100	gptg	399	gals	9.5	bbls	Mutual Solvent

Mixing Instruction:
1. Fill up tank with fresh water
2. Add additives as per above sequence
3. Agitate until mixture is homogeneous

15% HCl				3990	gals	95	bbls	Description
Seq	Product	Concentration		Volume				
1	Fresh Water	419	gptg	1,672	gals	39.81	bbls	Base Fluid
2	ACM CORR 400	4	gptg	16	gals	0.38	bbls	Acid Corrosion Inhibitor
3	MESB NE 200	4	gptg	16	gals	0.38	bbls	Non-Emulsifier
4	ACM Surf 210	3	gptg	12	gals	0.29	bbls	Surfactant
5	Ammonium Chloride	417	pptg	1,664	lbs			Clay Stabilizer
6	ACM Iron 300	25	pptg	100	lbs			Iron Sequestering
7	ACM Iron 200	15	gptg	60	gals	1.43	bbls	Iron Control
8	33% HCl	419	gptg	1,672	gals	39.81	bbls	Raw Acid
9	MESB MS 300	100	gptg	399	gals	9.50	bbls	Mutual Solvent

Mixing Instruction:
1. Fill up tank with fresh water
2. Add additives as per above sequence
3. Agitate until mixture is homogeneous

Treated Fresh Water				1050	gals	25	bbls	Description
Seq	Product	Concentration		Volume				
1	Fresh Water	959	gptg	1,007	gals	23.98	bbls	Base Fluid
2	MESB NE Surf 200	2	gptg	2	gals	0.05	bbls	Non-Emulsifier Surfactant
3	Ammonium Chloride	417	pptg	438	lbs			Clay Stabilizer
4	ACM OXYFREE 100	2	pptg	2	gals	0.05	bbls	Oxygen Scavenger
5	ACM H2SClear 200	2	gptg	2	gals	0.05	bbls	CO2 & H2S Corrosion Inhibitor
6	ACM BACT 200	2	gptg	2	gals	0.05	bbls	Microbiocide

Mixing Instruction:

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

51. 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

52. After completed fluid preparation, while CT station at XN Nipple at **1,968m / 6,457ft MDDF** with reference of Flag#2**,** proceed with pumping main treatment via coiled tubing as per below pumping schedule:

    52.1. Do not exceed MASTP/WHP of 1,100 psi during pumping operation.

    52.2. 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.

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

Acidizing Pumping Schedule via CT										
Stage	Start Depth (m)	End Depth (m)	Fluid at Reel Manifold	Fluid Entry Volume	Total Fluid Pumped (bbls)	Pump rate (bpm)	Fluid at nozzle	Surface Valve Config.	Remark	MASTP
1	1,968	1,968	Pre-Flush	25	25	0.5	Pre-Flush	Close	Pre-Flush at tip of Nozzle	1,100
2	1,968	1,968	Pre-Flush	65	90	0.5	Pre-Flush	Close	Pre-Flush start exit Nozzle	
3	1,968	1,968	15% HCl	25	115	0.5	15% HCl	Close	All Pre-Flush exit Nozzle	
4	1,968	1,968	15% HCl	65	180	0.5	15% HCl	Close	15% HCl start exit Nozzle	

5	1,968	1,968	TFW	25	205	0.5	TFW	Close	All 15% HCl exit Nozzle	
6	1,968	1,968	-		205	0.5	TFW	Open	**Station CT at safe depth** for Contingency Nitrogen unloading after complete soaking period	

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

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

54. Upon completing pumping all treatment fluid according to step 52, **soak the treatment for 2 hours**.

55. After complete **soaking for 2 hours**, manipulate surface valve as per the following position and flowback the well immediately to recover the total fluid pumped approximately **308 bbls** (1.5x total pumped fluid during stimulation).

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

56. Monitor the Differential pressure between CT Circulation Pressure and THP for not exceeding 1,500 psi at all times.

57. Ensure the Single Pump is already rig up at the tapping point of desander line. Mix Soda Ash to neutralize the flowback fluid as per the following recipe.

Neutralization Fluid				**50**	**BBL**	**Description**
Seq.	**Product**	**Concentration**		**Volume**		
1	Injection Water	976	gptg	49	bbls	Base fluid
2	Soda Ash	500	pptg	1,050	lbs	Neutralization fluid

Mixing Instruction:

1. Prepare injection water in the mixing tank.
2. Mix soda ash into tank and agitate until mixture is homogenous.

Note: The above recipe is for 50 bbls of Neutralization Fluid. Please prepare another batch if needed.

58. Monitor pH of return fluids and start injecting soda ash once pH reading is below than pH value obtained prior starting treatment. If no acid return observes on surface, continue flow the well without injecting soda ash.

59. Continuously monitor pH of return fluids constantly, every 30 minutes. Stop injecting soda ash when pH reading is equivalent to pH value prior starting treatment.

60. Record the following parameters during monitor well flowback. Include the following table in daily report.

Monitoring Checklist

Field/Platform/Well :
Engineer :

No.	Date	Time	Choke Size	pH.	% Water Cut	Bbl Counter	FLT	FTHP	Remark
1									
2									
3									
4									
5									
6									
7									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									

61. Once well is able to flow, POOH to surface.

62. In the event, well is unable to flow after 4 hours period, proceed to unloading the well by pumping Nitrogen to lighten the hydrostatic.

62.1. Pick up coil to first circulation point depth at **563-m MDDF** (calculated depth to create 500 psi underbalance, assuming fluid column full of TFW with 8.46 ppg), conduct pull test of at least 10m or more. Record the pulling weight both static and dynamic in the following table.

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

62.2. Upon completion pull test, continue to run in hole to 563 m MDDF.

62.3. Once coil at **563 m MDDF**, increase the N2 rate at 400 scf/min until 600 scf/min at this depth while monitoring the returns on the surface.

62.3.1. If there is fluid return on surface, continue to pump N2 until only gas return on surface which indicate that the column of fluid above CT BHA is lifted.

62.3.2. Constantly monitor & record the return from the well and THP. Periodically take fluid sample and verify the pH of fluid until achieve baseline pH fluid prior stimulation operation.

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

No.	Stage	Liquid Rate	Total Liquid	N2 Rate	Total N2	Duration	Coiled Tubing					
		BPM	BBL	SCFM	SCF	Minute	ft/min	From (ft)	From (m)	To (ft)	To (m)	Total Footage (ft)
1	POOH	0	0	300	37042	123	30	5551	1692	1847	563	3704
2	**Circulation***	0	0	400	12000	30	0	1847	563	1847	563	0
3	RIH	0	0	400	13343	33	30	1847	563	2848	868	1001
4	Pull test	0	0	400	1312	3	15	2848	868	2799	853	49
5	**Circulation**	0	0	400	12000	30	0	2799	853	2799	853	0
6	RIH	0	0	400	13343	33	30	2799	853	3799	1158	1001
7	Pull test	0	0	400	1312	3	15	3799	1158	3750	1143	49
8	**Circulation**	0	0	400	12000	30	0	3750	1143	3750	1143	0
9	RIH	0	0	400	13343	33	30	3750	1143	4751	1448	1001
10	Pull test	0	0	400	1312	3	15	4751	1448	4702	1433	49
11	**Circulation**	0	0	400	12000	30	0	4702	1433	4702	1433	0
12	RIH	0	0	400	11987	30	30	4702	1433	5601	1707	899
13	Pull test	0	0	400	1312	3	15	5601	1707	5551	1692	49
14	**Circulation**	0	0	400	12000	30	0	5551	1692	5551	1692	0
			Total N2, SCF		**154,307**							
			Total N2, Gallon		**1,657**							

***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*

63. Please note the maximum depth of circulation is at **1,692 m MDDF (300m above top perf of I-35U).** This is to avoid N2 and fluid losses to formation.
64. Stop pumping N2 once all the acid has been circulated out from well.
65. Once the well is flowing, stop pumping N2 and monitor the well flow for one hour
    65.1. If the well continues flowing naturally, start to pull coiled tubing out of the hole to surface and continue monitor the pH of fluid return until achieve baseline pH prior stimulation operation.
    65.2. If the well stops flowing naturally, repeat **step 62.3 by** pumping nitrogen again.
66. POOH CT to surface while pumping TIW at 0.3bpm. Ensure continuous return on surface is observe.
    66.1. Maximum coil speed while POOH is 50ft/min.
    66.2. Slow down coil speed to 10ft/min 50ft before and after passing through completion accessories.
67. Once CT on surface, close well and bleed off pressure in coil and stack up.

CONTINGENCY #1 – MILLING OPERATION WITH 2.72" PDC SCALE MILL BIT

All depths specified below are in m-MDDF (Drill floor to THF is 14.9-m as per tubing tally)

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

68. 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.

69. 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:

3. Prepare injection water in the mixing tank.
4. 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.

70. Make up 2-1/8" PDM Motor c/w PDC Scale Mill Bit tool as per **BHA#3: 2.72" PDC Scale Mill Bit BHA** in **Appendix I**.

71. Perform function test of the Milling Motor to determine at which pump rate and pressure the tool start to operate / rotate. Record the data in the table below and include in daily report. Refer to the Motor Performance data for the operating envelope. Recommended flowrate is **0.7 bpm to 1.3 bpm** (refer to the motor performance data).

Flow rates (bpm)		Pressure (psi)	Remark
GPM	BPM		
21.0	0.50		
30.0	0.71		
37.8	0.90		
46.2	1.10		
50.0	1.19		
60.0	1.43		

72. For reference, flow rate range to operate the motor is between 0.48 – 1.43 bpm as per the following specification.

WELLPRO GROUP

Motor Specifications

Motor Type	2 1/8" O.D. PRO TORQUE+	
Dimension and Connections		
	US Units	SI Units
Tool O.D.	2 1/8 inches	54 mm
Length	11.38 ft	3.47 m
Weight	90 lbs	40.9 kg
Top Connection	1 1/2" MT Box	
Lower Connection	1 1/2" MT Box	
Bearing Type	Fluid Lubricated	
Performance Date		
Lobe Configuration	5/6 (6.0 stage)	
Flow Rate	20 - 60 gpm	80 - 230 lpm
Speed (no load)	260 - 770 rpm	
	13.61 rev / gal	3.595 rev / l
Operational Torque @ Max Recommended Pressure	255 ft-lbs	346Nm
Operating Power Output	36 hp	27 kW
No Load Differential Pressure	60 psi	5.14 bar
Max Recommended Differential Pressure	1500 psi	103.4 bar
Tensile Specifications		
Max Continuous WOB	4,850 lbs	2,200 kg
Max WOB (w/o pumps)	9,700 lbs	4,400 kg
Maximum Bit Overpull (w/o damage)	23,800 lbs	10,795 kg
Maximum Bit Overpull	*31,200 lbs	14,152 kg
Max Temperature	300 ° F	150 ° C
Bit Size	2 3/8" - 3 1/2 + "	
Max Sand Content	1.50%	

73. Repeat Step 7 till 13 in Run#1.

74. Start running in hole coil tubing to **10m above previous HUD depth** in Run#1 with minimum pumping rate.

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

    74.2. 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 treatment report.

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

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

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

    74.6. Observe return all the times.

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

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

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

74.10. 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.

75. Once CT reach at **10m above HUD depth**, stop coil and 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*

76. Continue RIH slowly at 10ft/min without pumping to **HUD depth (with reference of flag in Run#1)**. Do not slack off more than 500 lbf.

77. Record the depth at which the HUD was tagged. Pick up CT to the normal weight and flag the coil on surface (Flag #).

Flag Number	*Colour*
Flag#	

78. Start pumping TIW to start the Milling Motor. Record all the parameter (Flow Rate, Pumping Pressure). Refer to the Motor Performance Data. Record the "Off Bottom" pump pressure prior milling.

78.1. The pressure is considered No Load Pressure **(P No Load).** No Load Pressure will increase as milling in progress.

Flow rates (bpm)		Pressure (psi)	Remark
GPM	BPM		
21.0	0.50		
30.0	0.71		
37.8	0.90		
46.2	1.10		
50.0	1.19		
60.0	1.43		

79. Once Off Bottom parameters have been recorded, increase pumping rate as per Milling Specialist recommendation and record the circulating pressure.

79.1. Do not exceed the maximum CT working pressure of 5,000 psi.

79.2. Flow rate range for the motor to operate is 0.48 – 1.43 bpm.

80. Continue to RIH until loss in weight (500 lbf slack off) is observed on mill and start milling while maintaining -500 lbf weight on bit. Record the bottom circulating pressure and start milling with minimum WOB.

Note: At this point, patience is critical. Motor stalls can occur repeatedly until milling pattern is established. Set down weight should be applied until approximately 300 – 400 psi differential pressure above the Off Bottom circulating pressure is maintained. Milling Specialist onsite will further asses the condition during milling operation.

80.1. Continue slacking off weight as differential pressure and ROP (Rate of Penetration) indicates the progress of scale milling. Keep WOB within limit as per Milling Specialist recommendation.

80.2. Regularly monitor return on surface, advise Milling Specialist immediately if there is no return while milling in progress. Flowback personnel must standby all the time at the Choke Manifold to monitor the choke size and keep the WHP/THP below 300 psi.

80.3. If observe debris at surface. Collect sample at DPSF and send to town for analysis.

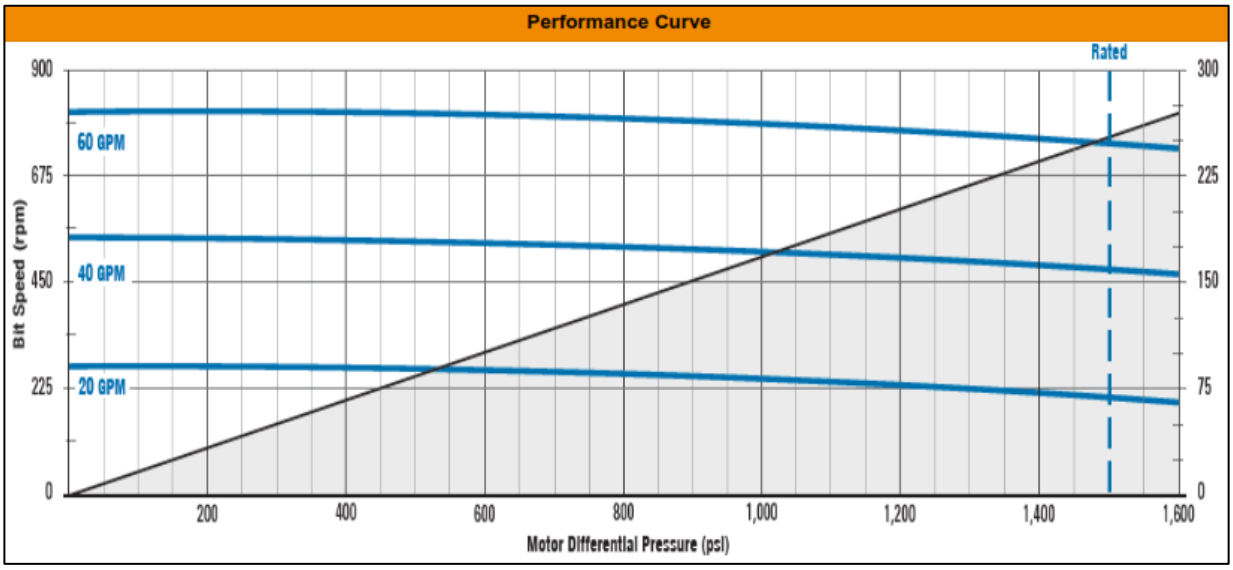
80.4. Set down weight between 500 to 1,500 lbf, in 100 lbf incremental. Maximum set down weight is 1,500 lbf. Motor work is indicated by differential pressure not the WOB.

80.5. Please record the bottom hole circulating pressure. Keep the DP between 300 – 700 psi. **Maximum DP is 1500 psi (P Load – P No Load).**

80.6. If motor stall, stop pumping, bleed off pressure and pick up CT 20ft above the current depth. Resume the pumping and note the pressure and compare to the previous pressure. Refer to the Motor Performance Curve below as guideline.

80.7. Monitor the return on surface at all time.

80.8. Milling Specialist to record all the parameter before milling and during milling manually in log sheet.



81. Once milling pattern is established, vary the set down weight between 500 to 1,500 lbf until achieve 500– 800 psi differential pressure. Maximum DP is 1500 psi.

82. Continue milling the **HUD depth** until encounter sudden lost weight that indicate the scale has been clear or fall to the next restriction inside the tubing.

82.1. Pay close attention to the weight indicator and circulation pressure gauge

82.1.1. The weight indicator will monitor the amount of WOB.

82.1.2. The circulation pressure gauge will inform the DP at which motor is functioning.

83. Once indication of the scale has been clear or fall to the next restriction, proceed to pump 41.5 bbls of D801 Gel and followed by 1.5x tubing volume with TIW to flush the remaining debris out from the well.

84. Once completed bottoms up, stop pumping and continue to RIH until XN Nipple at **1,968 m MDDF / 6,457 ft MDDF** to ensure there is no restriction until XN Nipple.

85. Slow down coil speed on 10m above XN Nipple. Record the depth of which CT encounter weight loss that indicate the location of the remaining scale. Flag the coil on surface (Flag#).

Flag Number	*Colour*
Flag#	

86. Once completed, continue to POOH CT to surface.
87. Once CT on surface, close well and bleed off pressure in coil and stack up. Prepare BHA for next run.

CONTINGENCY #2 - WELL UNLOADING

All depths specified below are in m-MDDF (Drill floor to THF is 14.9-m as per tubing tally)

88. This contingency run is made in case the well is still unable to flow upon SISQ treatment.
89. Make up 2-1/8" Upward Jetting Nozzle tool as per **BHA#4: 2-1/8" Upward Jetting Nozzle** in **Appendix I**.
90. Repeat step 7 till 13 in CT Run#1 procedure prior opening the well.
91. Start running in hole coil tubing to the first circulation point depth at **563-m MDDF** (calculated depth to create 500 psi underbalance, assuming fluid column full of TIW with 8.46ppg). Circulation point start at **563-m MDDF** (depth calculated to create 500 psi underbalance) until max depth at **1,692m MDDF** (1,000 ft above top perf of I-35U) to clear out fluid column inside tubing until well is able to flow.
    - 91.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix III.
    - 91.2. 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 treatment report.
    - 91.3. After pull test for every 300m RIH, perform break circulation by pump nitrogen at minimum pump rate permissible to ensure differential pressure between CT and Tubing is not more than 1,500ps.
    - 91.4. Maximum coil speed running in hole is **30-50 ft/min.**
    - 91.5. Slow down coil speed to **10 ft/min**, 50 ft before and after passing through completion accessories.
    - 91.6. Closely observe weight indicator in control cabin while running in hole.
    - 91.7. Observe return all the times.
    - 91.8. Regularly inform WSS on job status at all times.
    - 91.9. Do not exceed operating safety limits **5,000 psi.**
    - 91.10. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
    - 91.11. 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.
92. At **563-m MDDF**, 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*

93. Upon completion pull test, start pumping nitrogen with rate 400 scf/min until 600 scf/min for 30 minutes while monitoring the returns on surface.
    - 93.1. If fluid is observed at surface at a good flow rate, continue lifting until all fluid is recovered.
    - 93.2. Constantly monitor & record the return from the well and THP. Periodically take fluid sample and verify the salinity.
    - 93.3. If there is no fluid return at surface, continue pumping nitrogen and RIH to the next depth as per table below:

No.	Stage	Liquid Rate	Total Liquid	N2 Rate	Total N2	Duration	Coiled Tubing					
		BPM	BBL	SCFM	SCF	Minute	ft/min	From (ft)	From (m)	To (ft)	To (m)	Total Footage (ft)
1	RIH	0	0	300	10007	33	30	0	0	1001	305	1001
2	Pull test	0	0	300	984	3	15	1001	305	951	290	49
3	RIH	0	0	300	9449	31	30	951	290	1896	578	945
4	Pull test	0	0	300	984	3	15	1896	578	1847	563	49
5	**Circulation***	0	0	400	12000	30	0	1847	563	1847	563	0
6	RIH	0	0	400	13343	33	30	1847	563	2848	868	1001
7	Pull test	0	0	400	1312	3	15	2848	868	2799	853	49
8	**Circulation**	0	0	400	12000	30	0	2799	853	2799	853	0
9	RIH	0	0	400	13343	33	30	2799	853	3799	1158	1001
10	Pull test	0	0	400	1312	3	15	3799	1158	3750	1143	49
11	**Circulation**	0	0	400	12000	30	0	3750	1143	3750	1143	0
12	RIH	0	0	400	13343	33	30	3750	1143	4751	1448	1001
13	Pull test	0	0	400	1312	3	15	4751	1448	4702	1433	49
14	**Circulation**	0	0	400	12000	30	0	4702	1433	4702	1433	0
15	RIH	0	0	400	11987	30	30	4702	1433	5601	1707	899
16	Pull test	0	0	400	1312	3	15	5601	1707	5551	1692	49
17	**Circulation**	0	0	400	12000	30	0	5551	1692	5551	1692	0
			Total N2, SCF		**138,689**							
			Total N2, Gallon		**1,489**							

***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*

94. Please note the maximum depth of circulation is at **1,692m MDDF (1,000 ft above top perf of I-35U).** This is to ensure no nitrogen losses into formation.
95. Stop pumping N2 once get continuous gas return on surface.
96. Once the well start flowing, stop pumping nitrogen and monitor the well flow for **one hour.**
    96.1. If the well continues flowing naturally, start to pull coiled tubing out of the hole to surface.
    96.2. If the well stops flowing naturally, repeat **step 93** by pumping nitrogen again.
    96.3. In the event that after unloading the well was unsuccessful, consult town for further assistance whether to repeat nitrogen unloading.
97. 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.

Treated Sea Water (3% Friction Reducer)				10	BBL	Description
Seq.	Product	Concentration		Volume		
1	Injection Water	968	gptg	406	gal	Base Fluid
2	ACM H2S Clear 200	2	gptg	1	gal	CO2 & H2S Corrosion Inhibitor
2	IM Lube	30	gptg	13	gal	Friction Reducer
Mixing Instruction: 5. Prepare sea water in the mixing tank. 6. Add CO2 & H2S Scavenger and FR into the tank and circulate the mixture at least 10 minutes until homogenous.						

98. Upon well commencing to flow satisfactorily, POOH CT to surface.
    98.1. Pump N2 at minimum permissible rate while POOH. Do not exceed 5,000 psi pumping pressure.
    98.2. Maximum coil speed while POOH is 50ft/min.
    98.3. Slow down coil speed to 10ft/min 50ft before and after passing through completion accessories.
    98.4. Do not exceed CT Operating Limit.
99. Once CT on surface, close well, bleed off pressure in coil and stack up and handover well to PCSB.

BULLHEADING OPERATION – TUBING PICKLING

100. Line up transfer hose from IBC into mixing tank and 4" LP hoses from holding tank to single pump.

101. Line up 2" HP treating line from single pump to the wellhead.

102. Perform pressure test for the treating line against crown valve up to 500 psi and holds for 5 minutes and increase to 3000 psi and holds for 10 minutes.

103. Once completed, bleed off pressure through the bleed off line by fully opening the master plug valve (2x1 plug valve) then slowly open the control valve (2x1 plug valve). Ensure pressure is bled to zero.

104. Prior to start Tubing Pickling, record initial well pressure parameter & perform pre-treatment by collect well fluid sample before shut in well and record pH & water cut. This will be reference during flowback.

104.1. Record initial SITHP of short string and long string and PCP of well D-04S.

SITHP Short String	SITHP Long String	PCP

104.2. Label the sample bottle with type of sample, name of well, date and time the sample was collected.

Sample	Volume	pH Reading	Water Cut, %
Produced Fluid	1,000 mL		

105. Prepare treatment fluids as per below recipe for pumping activity:

PFA 200 (Pickling Solution)				68	BBL	Description
Seq	Product	Concentration		Volume		
1	PFA 200	1,000	gptg	2,856	gals	Base Fluid
Mixing Instruction: 1. Transfer PFA 200 from IBC into Tank and circulate the mixture until homogenous.						

106. Manipulate surface valve to the following position prior pumping activity:

Valve	Position
Flow Cross Pumping Valve (DB lines)	OPEN
Swab Valve	OPEN
Lower Master Valve	OPEN
Wing Valve	CLOSE

106.1. While opening up swab valve and lower master valve, count turns for future reference.

107. Prior start pumping activity, complete the following:

107.1. Record shut in tubing head pressure (THP) and casing head pressure (CHP). Include in daily report.

107.2. Bleed off tubing and casing pressure to 0 psi or to minimum as possible.

108. Open plug valve at the surface line that connects to pump-in tee and start pumping Pickling Solution according to the pumping table in Step 108.3.

108.1. **Do not exceed maximum allowable surface pressure 1,100psi.**

108.2. Ensure that one personnel is on standby at fluid storage tank during pumping to monitor fluid level.

108.3. Pumping sequence as per table below:

Pumping Schedule for Tubing Pickling						
Stage	**Description**	**Fluid**	**Vol (bbl)**	**Pump Rates (bpm)**	**Remarks**	**MASTP (psi)**
1	**Pickling Solution**	PFA 200	63	0.5	Tubing Pickling	1,100
2	**Displacement Fluid**	TIW	*	0.5	To displace all pickling solution in surface treating lines	1,100
Shut in well and soak for 4 hours						
Once complete, open up well & flowback to recover 95 bbls (1.5x total pumped fluid)						
• **Max WHP is 1,100 psi throughout pumping sequence.** • **Maintain pumping rate throughout the pumping stage. To compare injectivity index pre and post treatment.**						

108.4. Ensure that one personnel is on standby at fluid storage tank during pumping to monitor fluid level.

108.5. Record the following parameters while pumping. Include the following table in daily report.

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

109. Close well and **soak for 4 hours** after complete pumping 63 bbls of Pickling Solution.

110. After soaking for 4 hours, flow back well. Volume to recover on surface is at least **95 bbls** (1.5x volume pumped).

110.1. Take 500ml return sample after recovering 95 bbls of liquid on surface.

110.2. Label the sample as “PFA 200 flow back” along with time and date of sampling.

110.3. Record flow back observation as per table below and include in the daily report.

Time (min)	Observation (oil/water/mixed)	Volume (bbl)	THP SS (psi)	THP LS (psi)	CHP (psi)	Remark
Observation to be done every 15 minutes during PFA 200 flow back.						

111. Once flowback activity is completed (95 bbls fluid recover), inform WSS and close well prior proceed with next step.

BULLHEADING OPERATION – SISQ TREATMENT

112. Prior to perform SISQ treatment, proceed to fill up 179 bbls of TIW (1.5x completion volume of SS & LS) and perform injectivity test.

113. Prepare treatment fluids as per below recipe for pumping activity:

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 if needed.

114. Manipulate surface valve to the following position prior pumping activity:

Valve	Position
Flow Cross Pumping Valve (DB lines)	OPEN
Swab Valve	OPEN
Lower Master Valve	OPEN
Wing Valve	CLOSE

114.1. While opening up swab valve and lower master valve, count turns for future reference.

115. Prior start pumping activity, complete the following:

115.1. Record shut in tubing head pressure (THP) and casing head pressure (CHP). Include in daily report.

SITHP Short String	SITHP Long String	PCP

115.2. Bleed off tubing and casing pressure to 0 psi or to minimum as possible.

116. Open plug valve at the surface line that connects to pump-in tee and start pumping according to the pumping table in Step 117.

116.1. **Do not exceed maximum allowable surface pressure 1,100psi.**

116.2. Ensure that one personnel is on standby at fluid storage tank during pumping to monitor fluid level.

116.3. 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 SS (psi)	THP LS (psi)	CHP (psi)	Remark

117. Proceed with pump TIW to fill up completion volume (**179 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**	179 bbls or till return is observed on surface without N2 Injection	1.0	179 bbls is calculated based on 1.5x completion volume (SS, LS & Wellbore)	1,100

118. After complete pumping as per above pumping schedule, do not stop pumping and continue pumping at idle rate.

118.1. Ensure Baker Hughes EIC is available and witness the injectivity test.

118.2. Sustain each pumping rate for 5 minutes after pressure stabilises. For last achievable rate, prolong the monitoring for 15 minutes.

118.3. DO NOT exceed MASP 1,100 psi.

118.4. **Proposed injection rate for SISQ treatment is 3 – 5 bpm.**

118.5. Begin injectivity test as per table below:

Rate (bpm)	Pumping Pressure (psi)	Time (min)	Volume (bbls)	THP SS (psi)	THP LS (psi)	CHP (psi)
0.30						
0.50						
0.70						
1.00						
1.50						
2.00						
2.50						
3.00						
3.50						
4.00						
4.50						
5.00						

119. Fill up table and include in daily report. Report the results of injectivity test to WSS, Baker Hughes EIC and DB EIC.

120. Upon completion of injectivity test and get approval from EIC to proceed with main treatment, prepare treatment fluid as per below:

120.1. Ensure that all personnel involved in mixing are in a full required PPE for acid job.

Pre-Flush Solvent				50	BBL	Description
Seq	Product	Concentration		Volume		
1	Injection Water	999	gptg	2,098	gals	Base Fluid
2	SISQ (SCW82451)	1	gptg	2	gals	SISQ

Mixing Instruction:
1. Prepare fresh water into mixing tank
2. Transfer SCW82451 from IBC into Tank and circulate the mixture until homogenous.

Main Treatment (SISQ SCW82451)				660	BBL	Description
Seq	Product	Concentration		Volume		
1	Injection Water	900	gptg	24,948	gals	Base Fluid
2	SISQ (SCW82451)	100	gptg	2,772	gals	SISQ

Mixing Instruction:
1. Prepare fresh water into mixing tank
2. Transfer SCW82451 from IBC into Tank and circulate the mixture until homogenous.

Post Flush (Treated Injection Water)				2112	BBL	Description
Seq	Product	Concentration		Volume		
1	Injection Water	1000	gptg	8,704	gals	Base Fluid

Mixing Instruction:
1. Prepare treated injection water into mixing tank

121. Once all fluids are readily mix, prepare for pumping operation.

122. Manipulate Surface valve to the following position prior pumping activity;

Valve	Position
Flow Cross Pumping Valve (DB lines)	OPEN
Swab Valve	OPEN
Lower Master Valve	OPEN
Wing Valve	CLOSE

122.1. While opening up swab valve and lower master valve, count turns for future reference.

123. Prior start pumping activity, complete the following:

123.1. Record shut in tubing head pressure (THP) and casing head pressure (CHP). Include in daily report.

SITHP Short String	SITHP Long String	PCP

123.2. Bleed off tubing and casing pressure to 0 psi or to minimum as possible.

124. Commence pumping as per below pumping schedule:

SISQ Treatment for I-35U									
Stage	Description	Pump #1			Pump #2			Remarks	MASTP (psi)
		Fluid	Vol (bbl)	Pump Rates (bpm)	Fluid	Vol (bbl)	Pump Rates (bpm)		
1	**Preflush**	0.1% of SISQ in TIW	50	5.0				To condition the well	1,100
2	**Main Treatment**	SISQ SCW82451	66	0.5	TIW	594	4.5	Scale Inhibitor (10% of SCW 82451 in TIW)	1,100
3	**Overflush**	TIW	2,112	5.0				To push SISQ 22.8ft in treatment zone	1,100
4	**Displacement**	TIW	*	1.0				To displace surface line	1,100
Shut in well and soak for 12 hours									
Flowback well once complete 12 hours soaking									

- **Ensure Baker Hughes EIC is available on-site during main treatment pumping.**
- **Optimum pumping rate will be advised by Baker Hughes EIC without exceeding capacity of pumping unit.**

Note: * Volume of surface treating line.

125. Record the following parameters while pumping. Include the following table in daily report.

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

126. Upon completing pumping all treatment fluid according to step 124, **soak the treatment for 12 hours**.

127. After complete **soaking for 12 hours**, manipulate surface valve as per the following position and flowback the well immediately to recover the total fluid pumped approximately **4,233 bbls** (1.5x total pumped fluid during stimulation).

Valve	Position
Flow Cross Pumping Valve (DB lines)	CLOSE
Swab Valve	CLOSE
Lower Master Valve	CLOSE
Wing Valve	OPEN

128. Ensure Chemical Injection Pump is already rigged up at data header tapping point and soda ash is mixed. Refer to table below for soda ash recipe:

Neutralization Fluid (Soda Ash)				50	BBL	Description
Seq	Product	Concentration		Volume		
1	Injection Water	976	gptg	49	bbl	Base Fluid
2	Soda Ash	500	gptg	1,050	lbs	Neutralization Fluid

Mixing Instruction:
1. Prepare injection water into mixing tank
2. Mix soda ash into tank and agitate until the mixture is homogenous.

129. Start injecting soda ash once acid return or after **2,112 bbls** of fluid recovered on surface (estimated first acid return on surface). If no acid return observed on surface, continue flow the well without injecting soda ash.

130. Monitor pH of return fluids constantly, every 60 minutes. Stop injecting soda ash when pH reading is equivalent to pH value prior starting treatment.

131. Record the following parameters during monitor well flowback. Include the following table in daily report.

Monitoring Checklist

Field/Platform/Well :
Engineer :

No.	Date	Time	Choke Size	pH.	% Water Cut	Bbl Counter	FLT	FTHP	Remark
1									
2									
3									
4									
5									
6									
7									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									

132. Once flowback activity is completed (**4,233 bbls** fluid recover), inform WSS and handover well to production.

133. In the event well unable to flow, proceed to **step 88** as stated in **CT Contingency#2**.

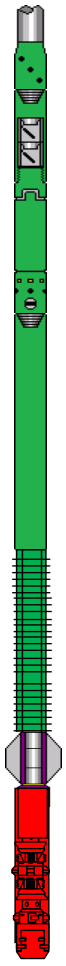
134. Proceed with equipment rig down upon receiving instruction to do so.

APPENDIX I – BOTTOM HOLE ASSEMBLY SCHEMATIC
BHA #1: 1.69" SPINCAT NOZZLE

DIMENSION BID
WELL INTERVENTION | PERFORATION SERVICES

BHA DIAGRAM #1- 1.69" SPINCAT NOZZLE

Client	Petronas Carigali	Well	D-04S
Field	Angsi Delta	Min Restriction	2.69"
Job Type	SCO & Stimulation	BHP	2173 psi
Job No.		BHT	242.9 F

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	**Internal Dimple CT Connector**	1.5" CT	1.0" AMMT PIN		1.690	0.3	0.3
	1-11/16" 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	2.6
	1-11/16" 5 ft Straight Bar	1.0" AMMT BOX	1.0" AMMT PIN		1.690	5.0	7.6
	1-11/16" Downhole Filter	1.0" AMMT BOX	1.0" AMMT PIN		1.690	3.20	10.8
	1-11/16" SpinCat c/w 2.25" Drift Ring	1.0" AMMT BOX			2.250	1.5	12.3

BHA LENGTH	12.30
MAXIMUM OD	2.25
MINIMUM ID	

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

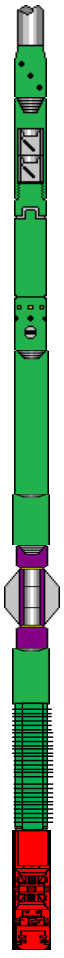
ADDITIONAL INFORMATION:

BHA #2: 1.69" SPINCAT NOZZLE C/W 2.75" FLUTED CENTRALIZER

DIMENSION BID
WELL INTERVENTION | PERFORATION SERVICES

BHA DIAGRAM #2 - 1.69" SpinCat Nozzle c/w 2.75" Fluted Centralizer BHA

Client	Petronas Carigali	Well	D-04S
Field	Angsi Delta	Min Restriction	2.69"
Job Type	SCO & Stimulation	BHP	2173 psi
Job No.		BHT	242.9 F

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	**Internal Dimple CT Connector**	1.5" CT	1.0" AMMT PIN		1.690	0.3	0.30
	1-11/16" 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	2.60
	1.69" 5 FT Straight Bar	1.0" AMMT BOX	1.0" AMMT PIN		1.690	5.0	7.60
	2-1/8 X-Over Adapter	1.0" AMMT BOX	1.5" AMMT PIN		2.125	0.40	8.00
	2.75" FT Fluted Centralizer	1.5" AMMT BOX	1.5" AMMT PIN		2.750	1.0	9.00
	2-1/8 X-Over Adapter	1.5" AMMT BOX	1.0" AMMT PIN		2.125	0.40	9.40
	1-11/16" Downhole Filter	1.0" AMMT BOX	1.0" AMMT PIN		1.690	3.20	12.60
	1-11/16" SpinCat	1.0" AMMT BOX	1.0" AMMT PIN		1.690	1.00	13.60

BHA LENGTH	13.60
MAXIMUM OD	2.75
MINIMUM ID	

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

ADDITIONAL INFORMATION:

BHA #3: MILLING BHA

BHA Schematic

Job Number:	WPG-AP-10297
Customer:	Dimension Bid / PCSB
Rig/Rigless:	Rigless
Well Number:	D-04S
Minimum Well Restriction:	2.69" @ XN-NO GO
Bottom Hole Temperature:	243 F
PCE Stack ID (in):	
BHA Name and Run #:	Milling
Date Drawn:	12/8/2022

WELLPRO GROUP

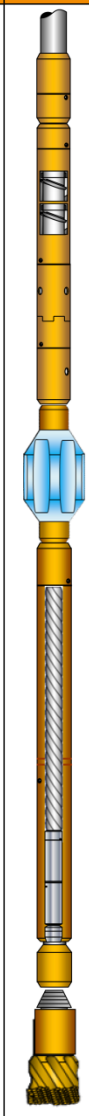
BHA to be drawn by Wellpro Group supervisor, Checked by the Coiled Tubing supervisor and WSS

Item	Tool Description & Serial Number	Details (ball, disc & F/N)	Connection (Up)	Connection (Down)	MUT (ft/lbs)	Tool OD (in.)	Tool ID (in.)	Length (FT)
1	External Dimple Connector		1.50" CT	1.5" AMMT Pin	950	2.250	1.000	0.840
2	Motorhead Assembly	3/4" Disc 5/8" Circ 5k psi RD	1.5" AMMT Box	1.5" AMMT Pin	950	2.125	0.563	2.390
3	NRT Stabilizer Stabiliser Sleeve *(optional)*		1.5" AMMT Box	1.5" AMMT Pin	950	2.620	0.750	2.080
4	Wellpro Pro-Torque Motor		1.5" AMMT Box	1.5" AMMT Box	950	2.125	n/a	11.400
5	Scale Mill Bit		1.5" AMMT Pin	n/a	950	2.720	n/a	1.00
6								
7								
8								

Additional Information:				
	Max Tool-String OD:		2.72	
	Minimum Tool-String ID:			0.56
	Total Length of BHA:			17.71
	Lowest Tensile Rating (lbs):			

Thread Type	M/U Torque values	Tensile Yield
1" Ammt	500 Ft/lbs	68,100lbs
1 1/2" Ammt	950 Ft/Lbs	127,700lbs
2 3/8" Std Pac	2,400 Ft/Lbs	238,440lbs
2 3/8" Pac DSI	3,250 Ft/Lbs	201,900lbs
2 3/8" API Reg	3,700 Ft/Lbs	375,500lbs

Tensile ratings above based on material yield of 120k psi

Item	Tool Icon	Item	Tool Icon
1			
2			
3			
4			
5			

BHA Prepared/Drifted by :		Witnessed By:	
Signature:		Signature:	

F 21 Rev 1 BHA Assembly Drawing

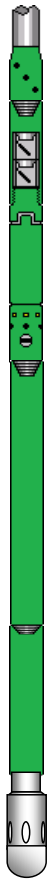
BHA #4: 2-1/8" UPWARD JETTING NOZZLE

DIMENSION BID
WELL INTERVENTION | PERFORATION SERVICES

BHA DIAGRAM #5 - 2-1/8" Upward Jetting Nozzle

Client	Petronas Carigali
Field	Angsi Delta
Job Type	SCO & Stimulation
Job No.	

Well	D-04S
Min Restriction	2.69"
BHP	2173 psi
BHT	242.9 F

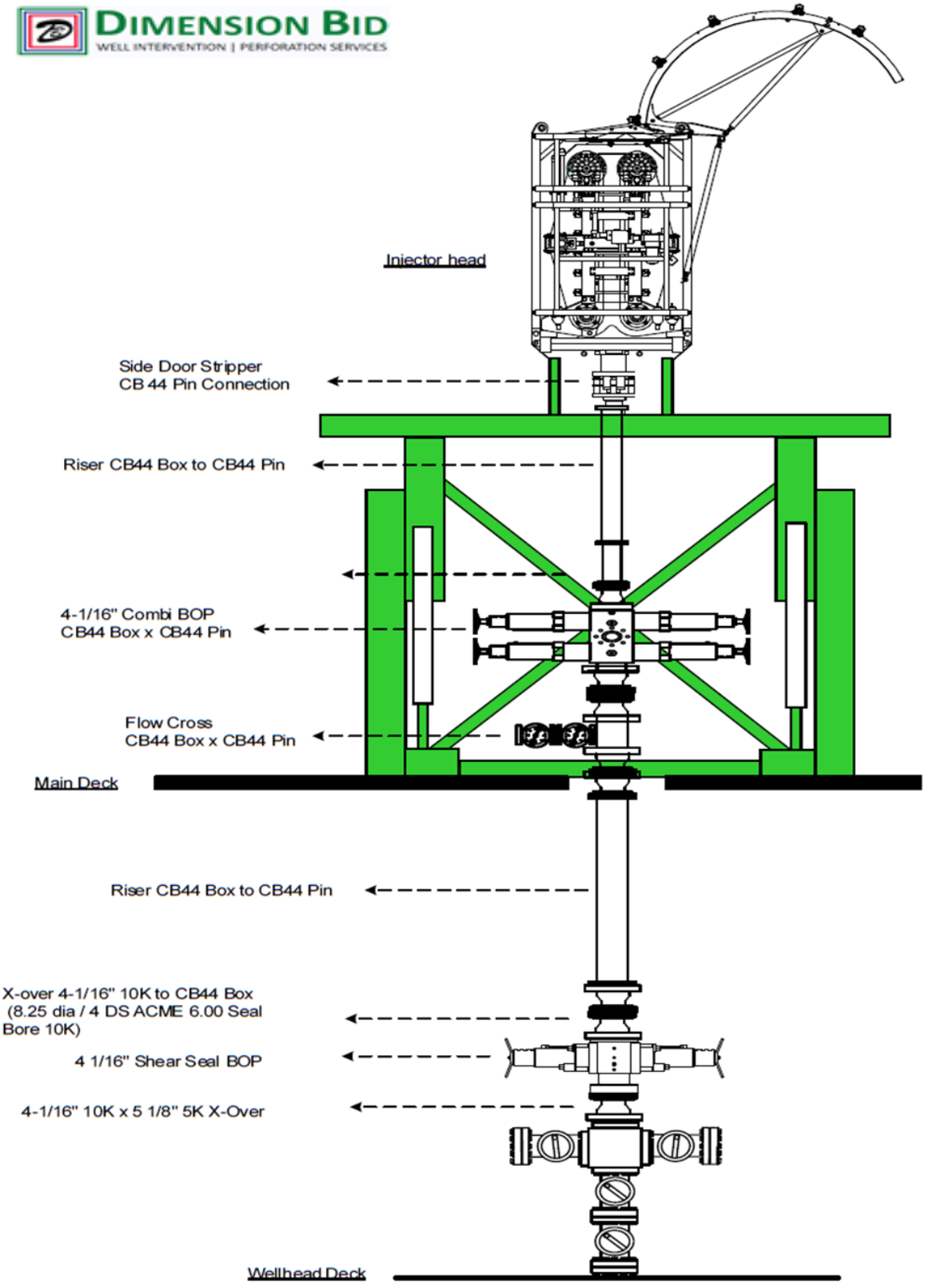
BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	**External Dimple Connector**	1.5" CT	1.5" AMMT PIN		2.125	0.6	0.6
	MHA Disconnect drop ball 3/4" Shear pressure 5,636 psi Circulating drop ball 10/16" Shear pressure 2,932 psi Burst Disc 5000 psi	1.5" AMMT BOX	1.5" AMMT PIN		2.125	2.5	3.1
	5 FT Straight Bar	1.5" AMMT BOX	1.5" AMMT PIN		2.125	5.0	8.1
	3 FT Straight Bar	1.5" AMMT BOX	1.5" AMMT PIN		2.125	3.0	11.1
	45° Upward Jetting Nozzle	1.5" AMMT BOX			2.125	0.60	11.7

BHA LENGTH	11.70
MAXIMUM OD	2.13
MINIMUM ID	

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

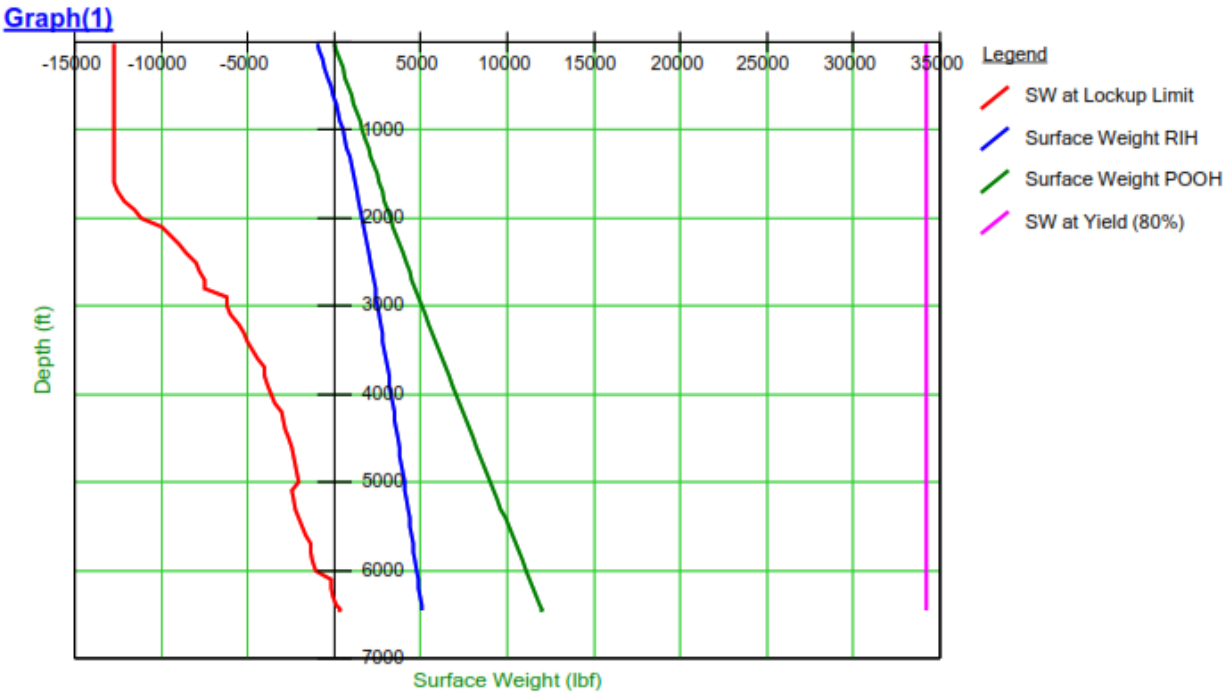
ADDITIONAL INFORMATION:

APPENDIX II – COILED TUBING STACK UP

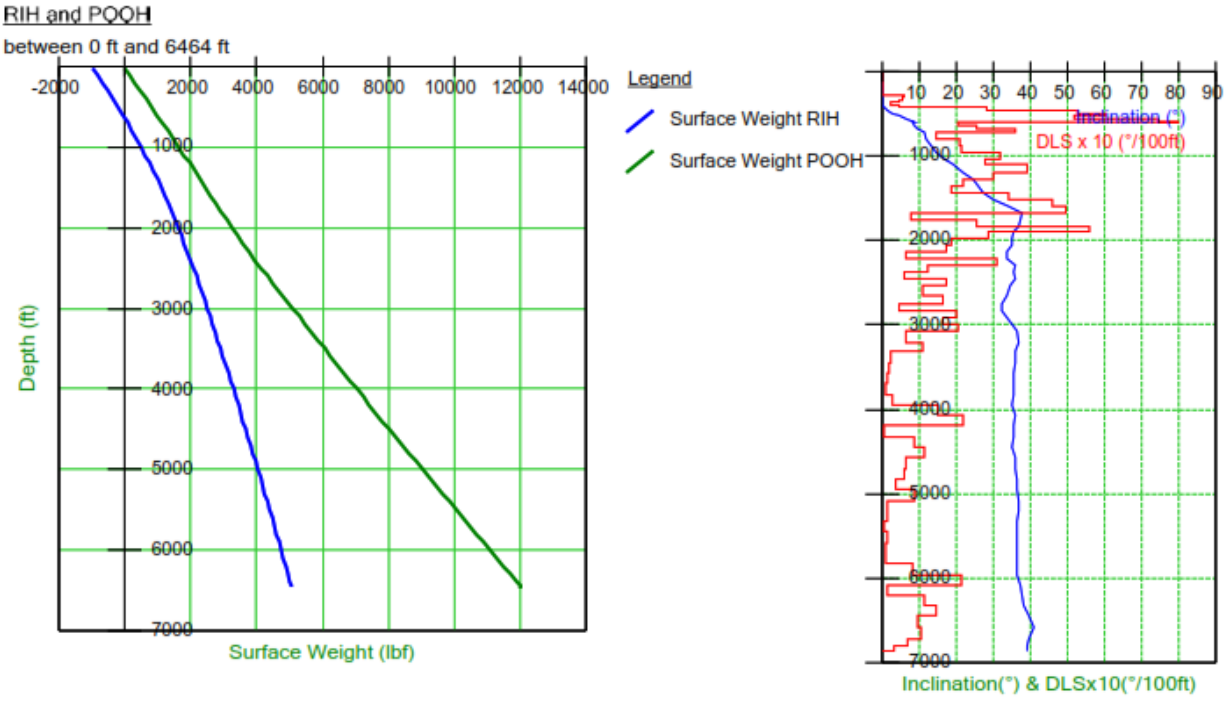


APPENDIX III – ORPHEUS SIMULATIONS

TUBING FORCE ANALYSIS (0.3 BPM of TIW with SpinCat Nozzle)

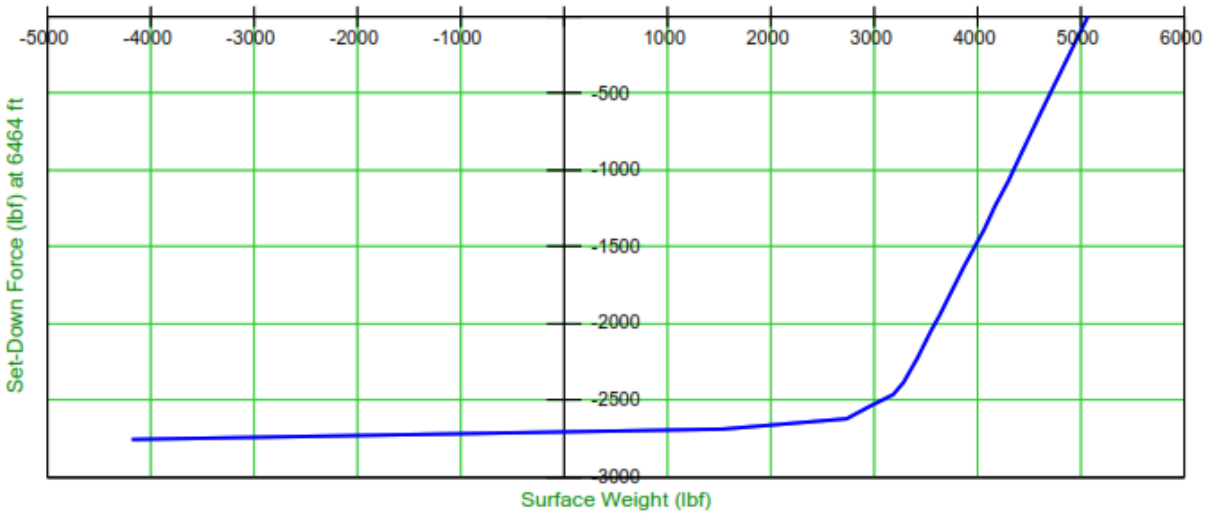


RIH & POOH WEIGHT



MAXIMUM STRING SET DOWN LIMIT

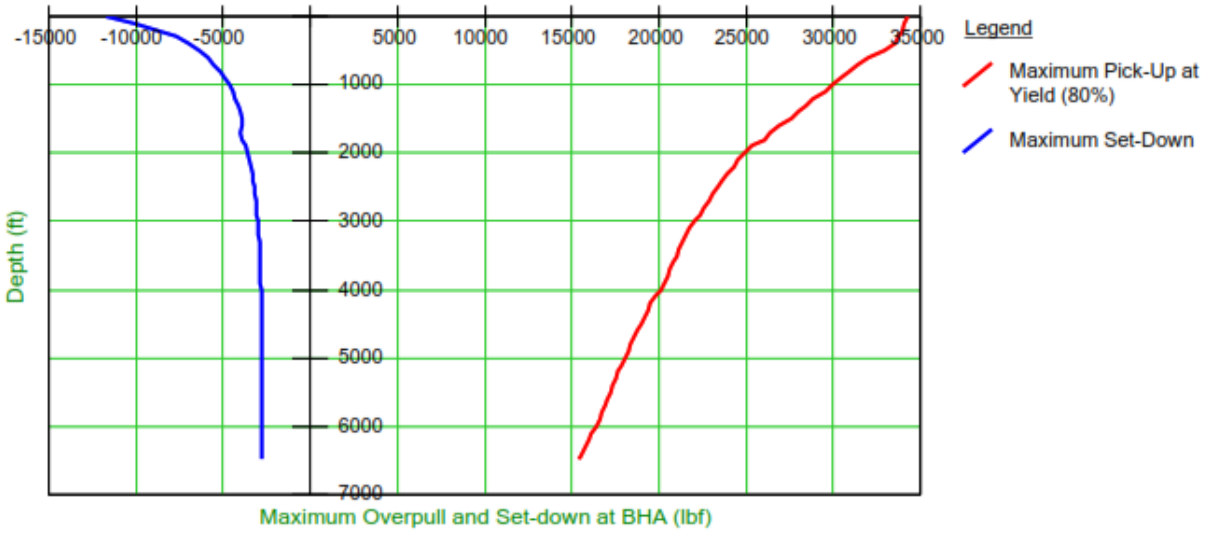
MD3 The available set-down force at 6464 ft is -2756 lbf at the end of the string.
The weight indicator reading will be 367 lbf on surface.
The minimum available set-down force is -2745 lbf at 5000 ft.



MAXIMUM STRING PICK UP LIMIT

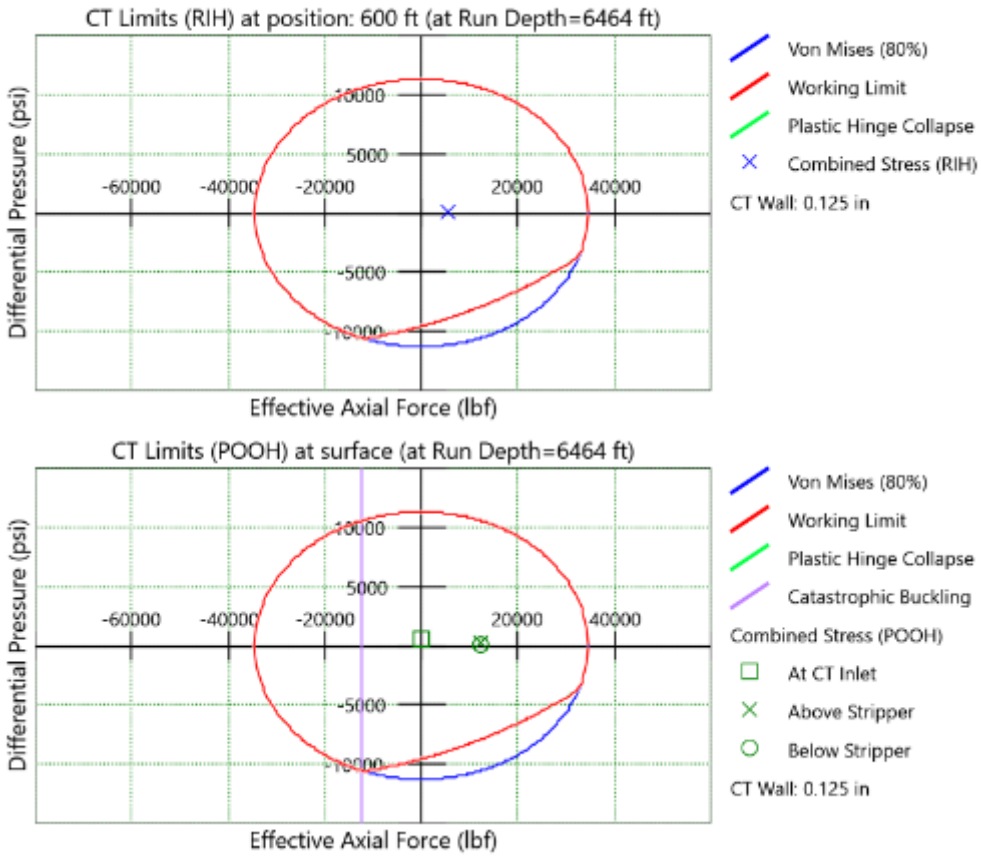
Calculations at 6464 ft

MD1 The available pick-up at 6464 ft based on 80% of yield strength is 15439 lbf.
The weight indicator reading will then be 34241 lbf.

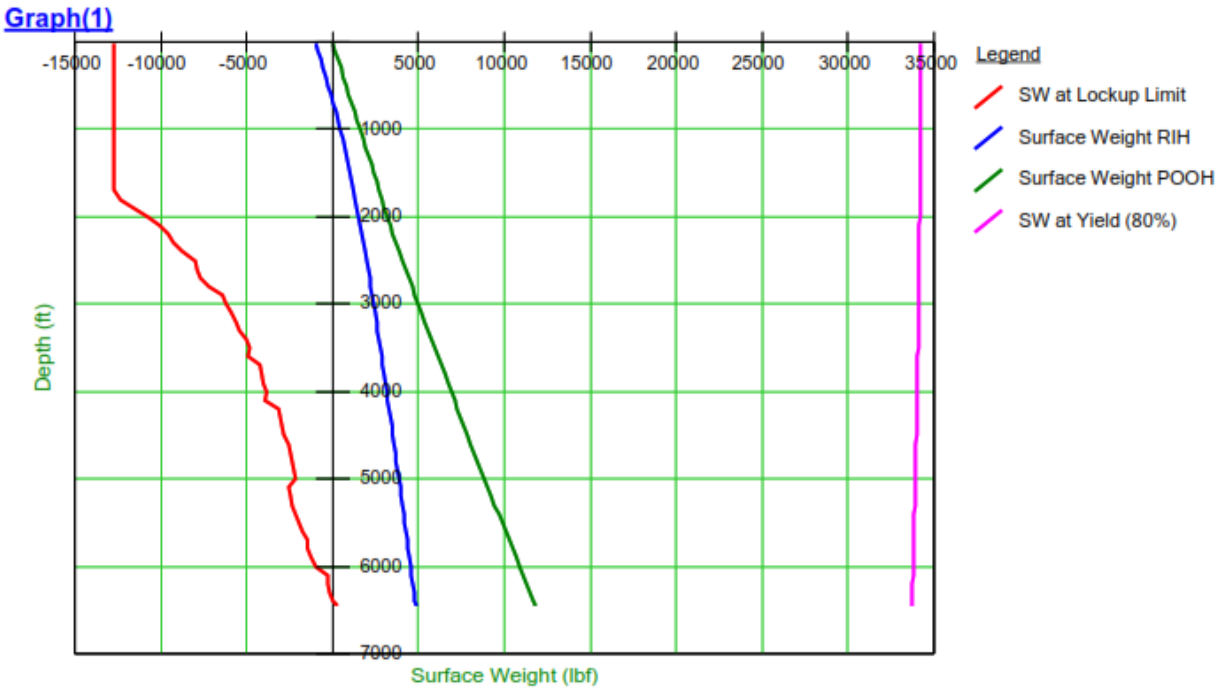


STRING LIMIT

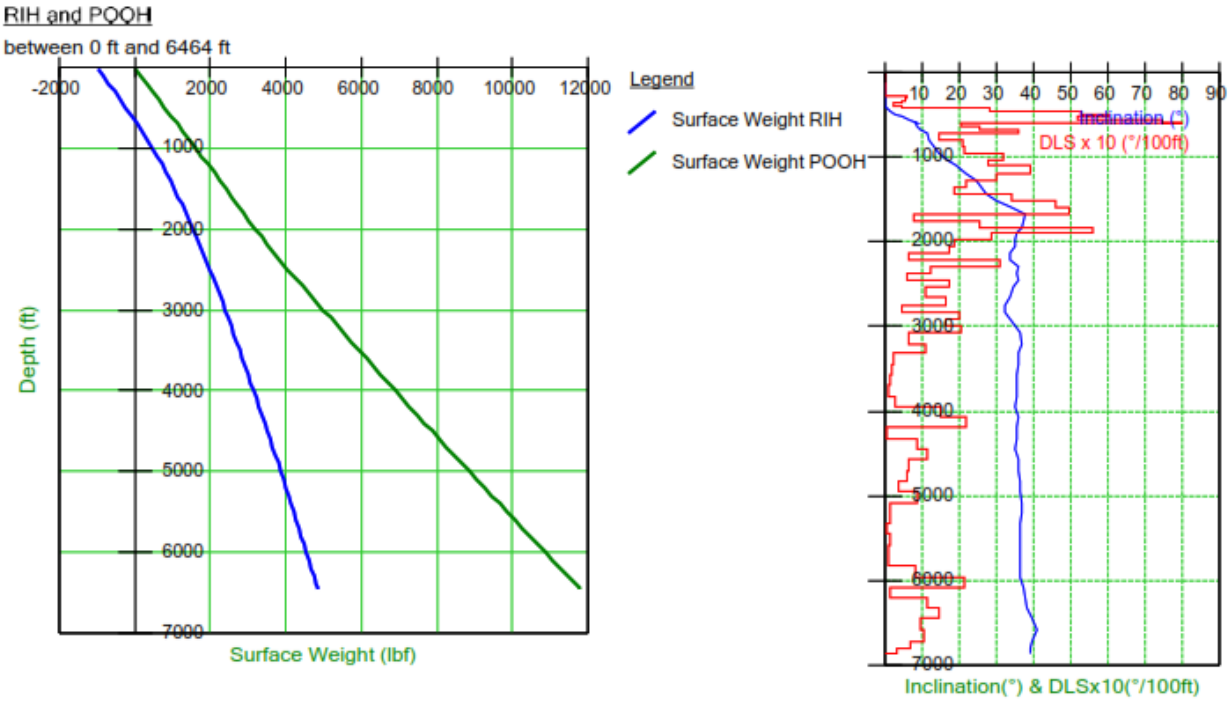
CT Limits



TUBING FORCE ANALYSIS (1.2 BPM of TIW with SpinCat Nozzle)

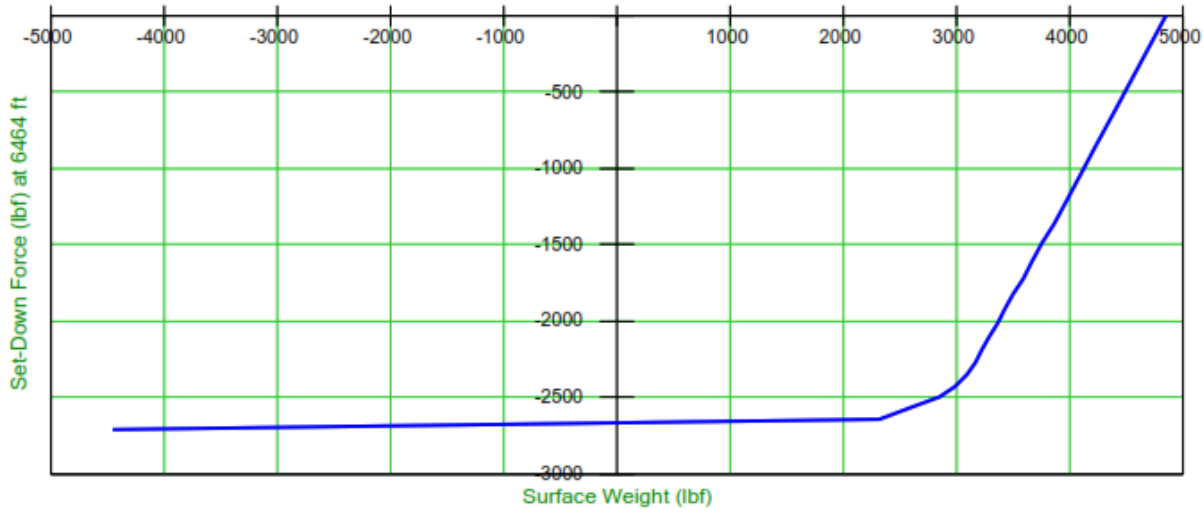


RIH & POOH WEIGHT



MAXIMUM STRING SET DOWN LIMIT

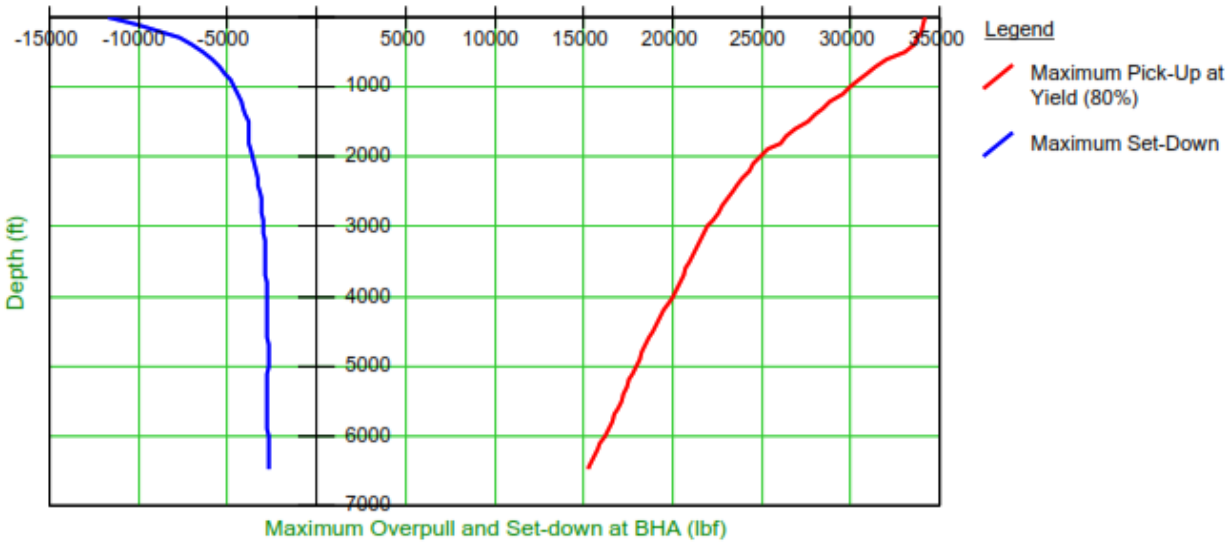
MD3 The available set-down force at 6464 ft is -2710 lbf at the end of the string.
The weight indicator reading will be 240 lbf on surface.
The minimum available set-down force is -2703 lbf at 5000 ft.



MAXIMUM STRING PICK UP LIMIT

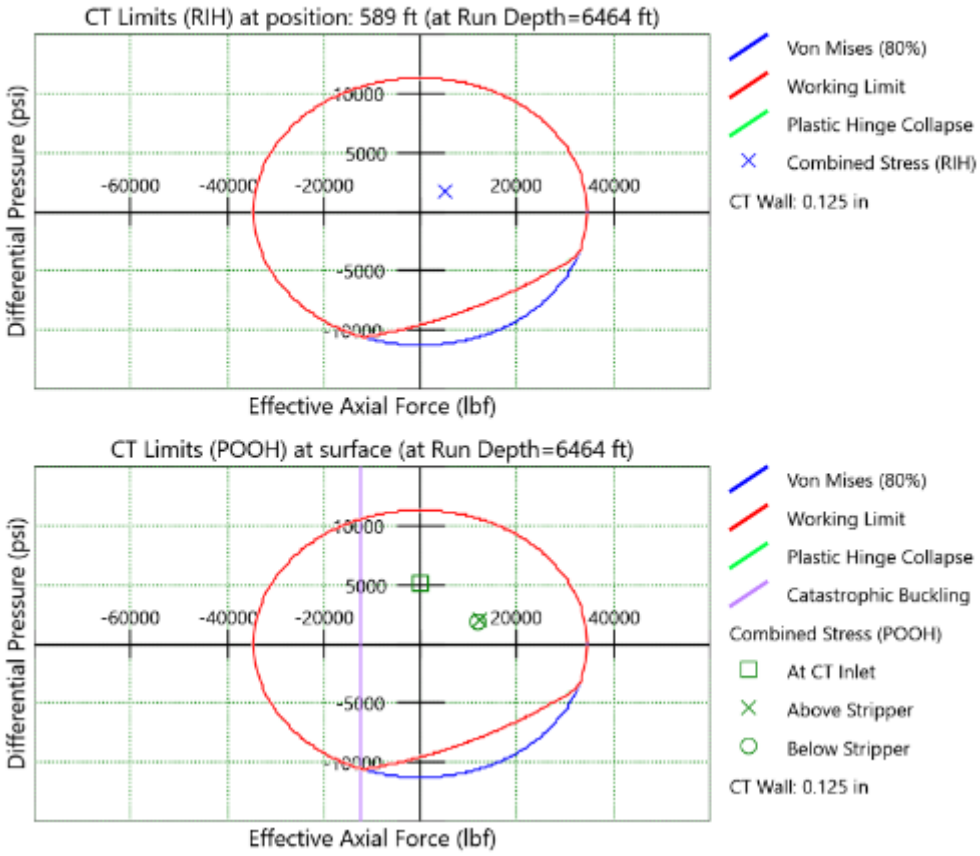
Calculations at 6464 ft

MD1 The available pick-up at 6464 ft based on 80% of yield strength is 15244 lbf.
The weight indicator reading will then be 33706 lbf.

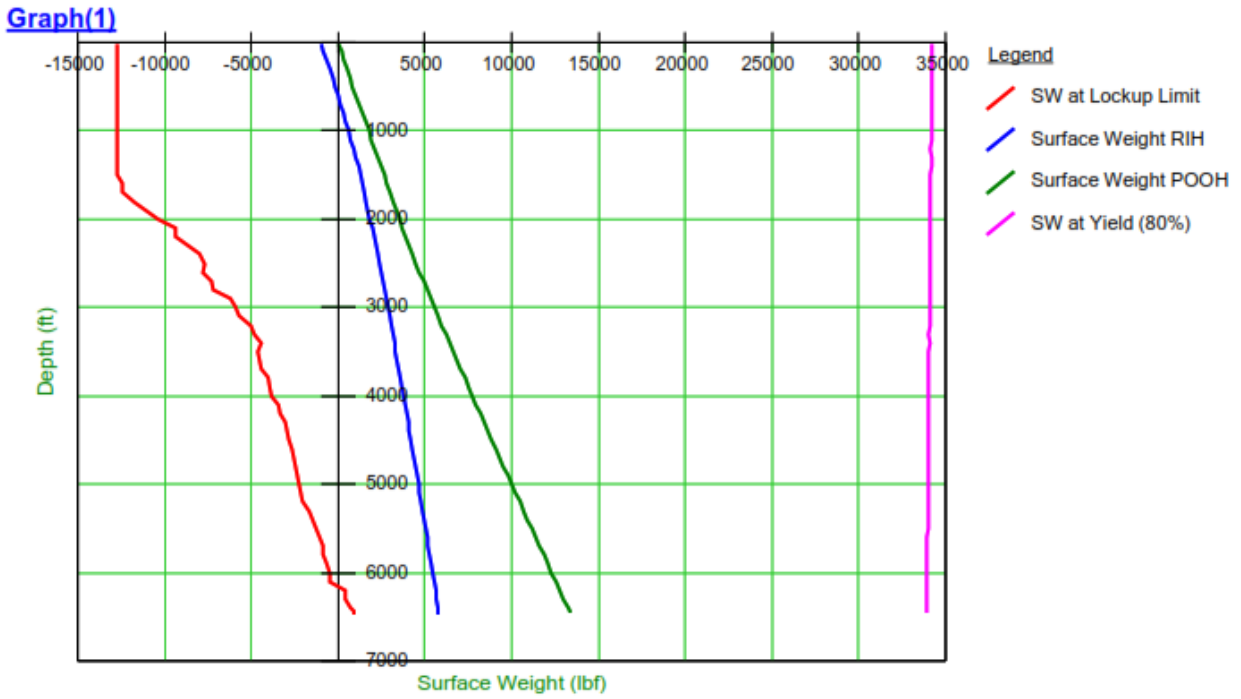


STRING LIMIT

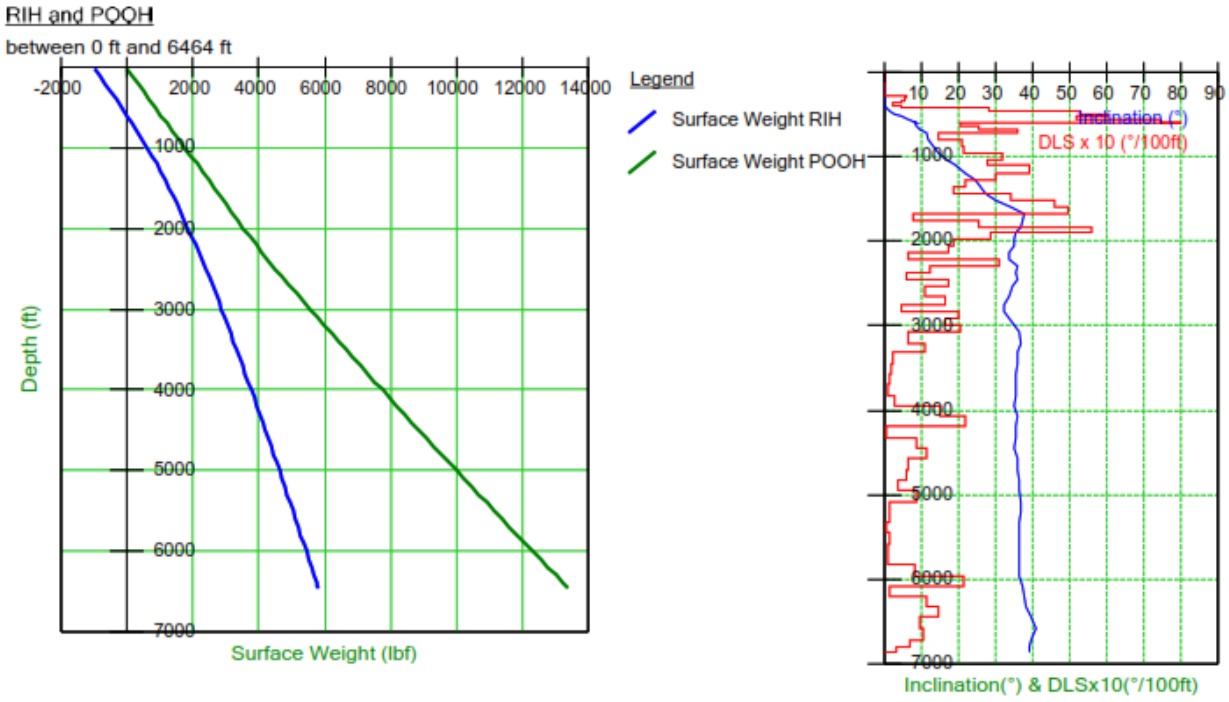
CT Limits



TUBING FORCE ANALYSIS (1.0 bpm of TIW & 300 scfm N2 with SpinCat Nozzle)

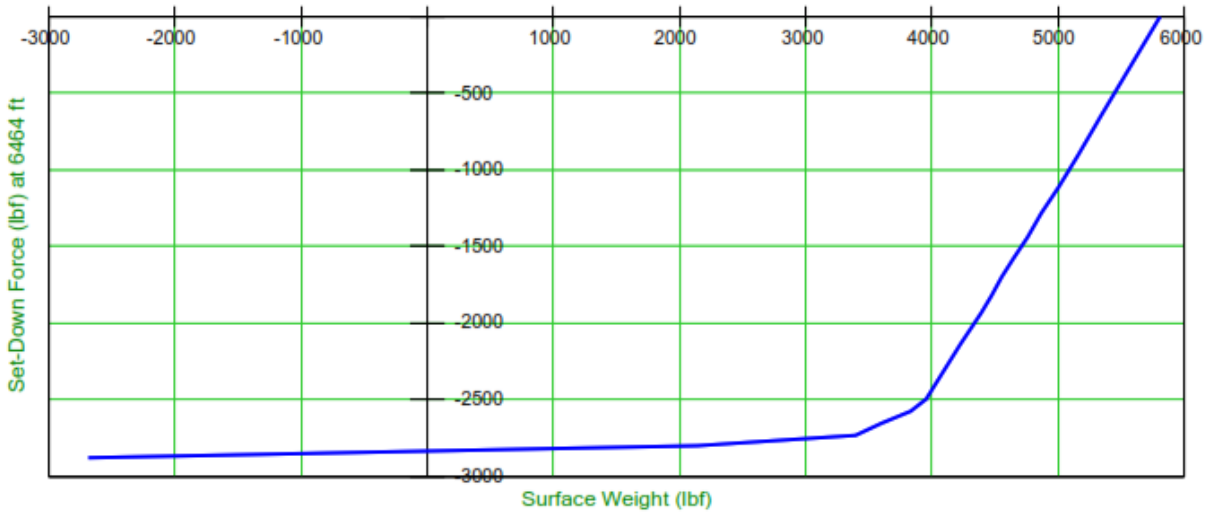


RIH & POOH WEIGHT



MAXIMUM STRING SET DOWN LIMIT

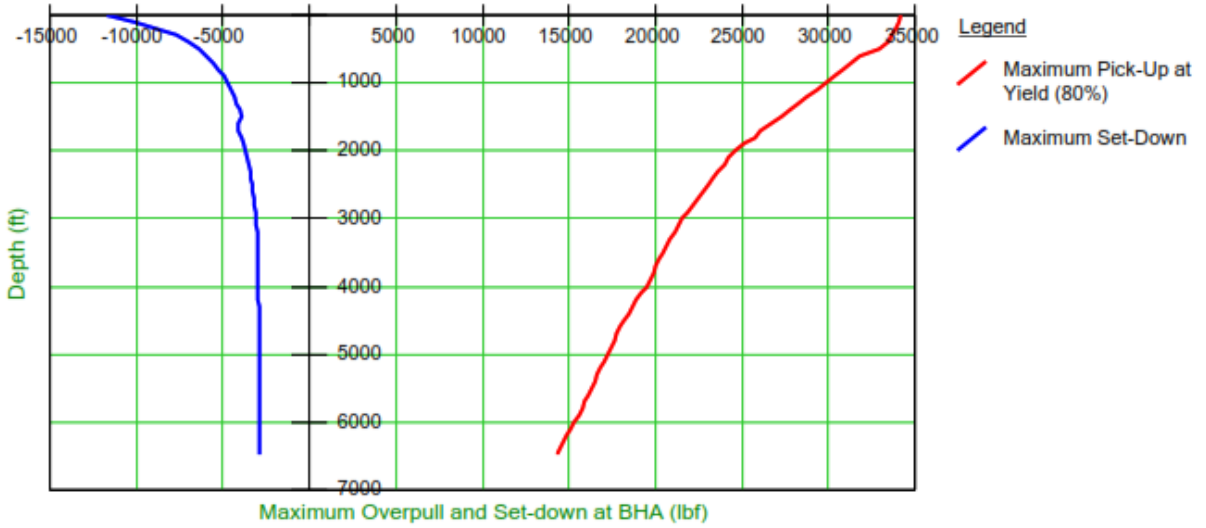
MD3 The available set-down force at 6464 ft is -2874 lbf at the end of the string.
The weight indicator reading will be 974 lbf on surface.
The minimum available set-down force is -2873 lbf at 6457 ft.



MAXIMUM STRING PICK UP LIMIT

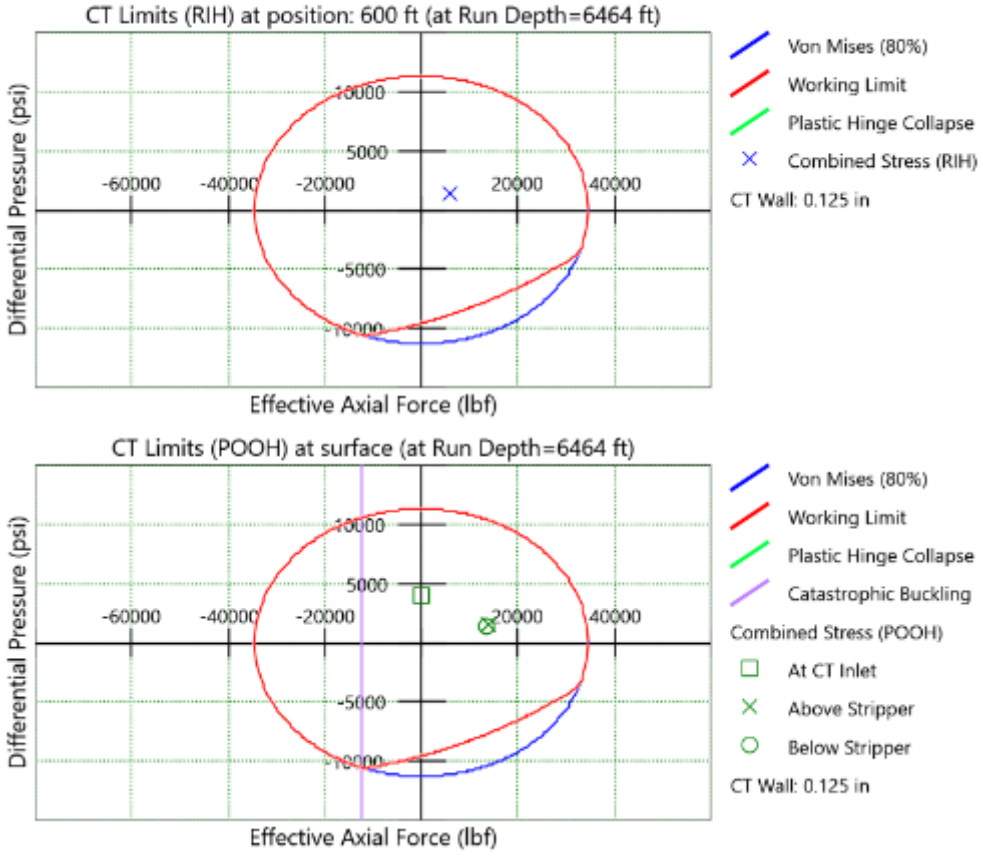
Calculations at 6464 ft

MD1 The available pick-up at 6464 ft based on 80% of yield strength is 14326 lbf.
The weight indicator reading will then be 33903 lbf.

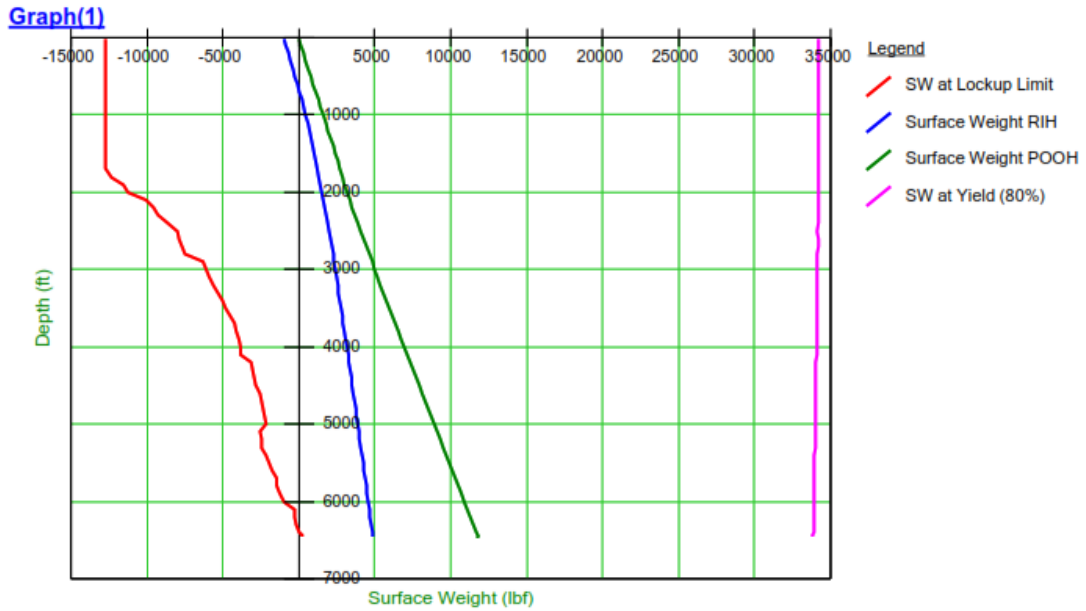


STRING LIMIT

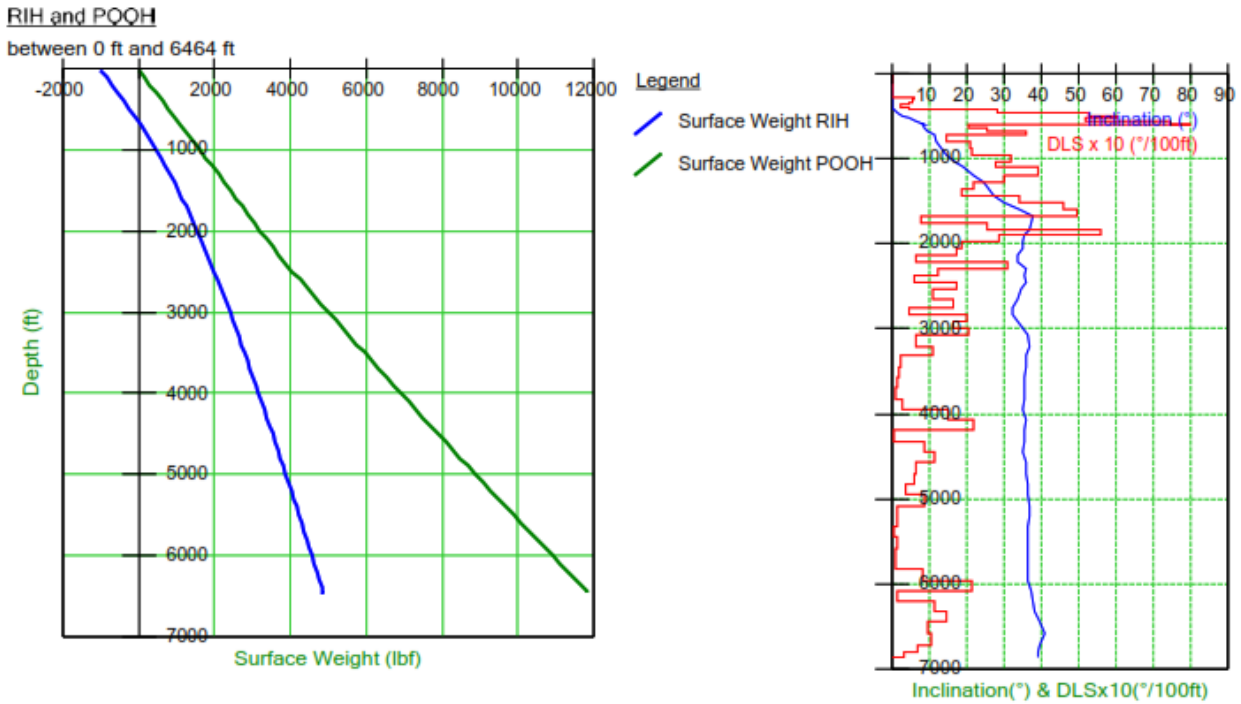
CT Limits



TUBING FORCE ANALYSIS (1.1 bpm of TIW with milling BHA)

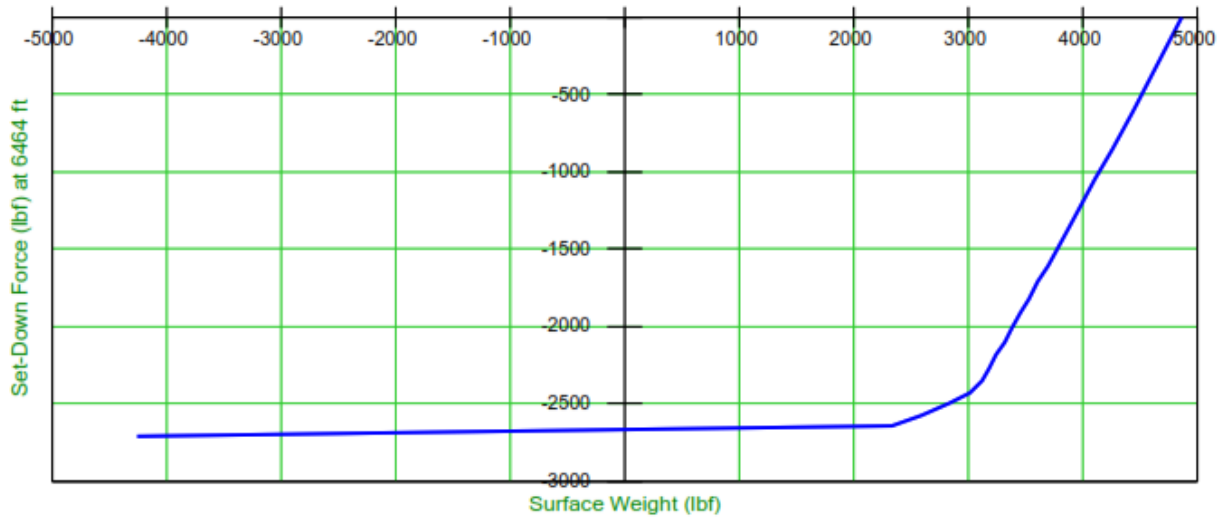


RIH & POOH WEIGHT



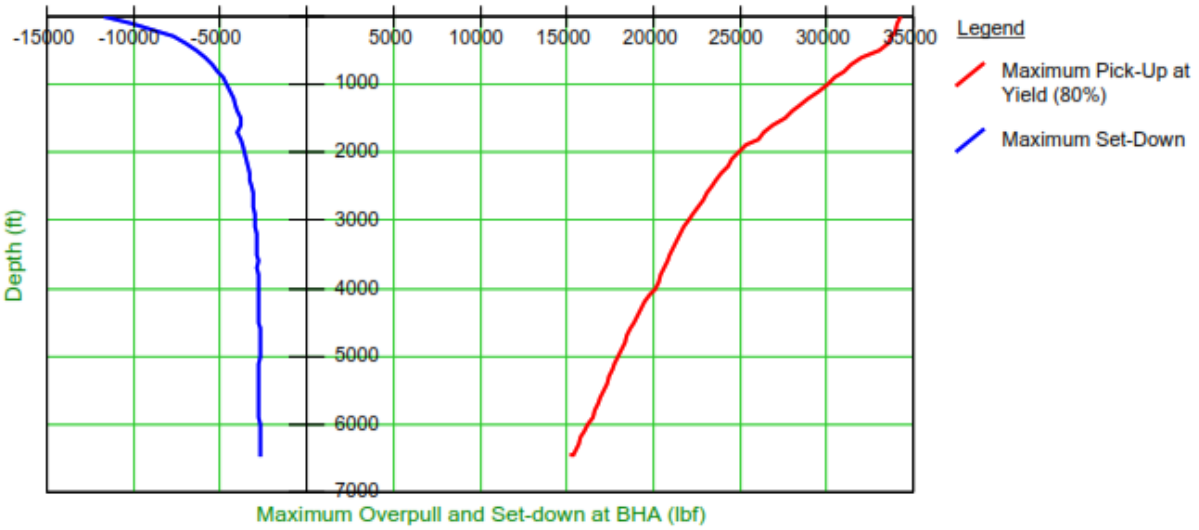
MAXIMUM STRING SET DOWN LIMIT

MD3 The available set-down force at 6464 ft is -2708 lbf at the end of the string.
The weight indicator reading will be 261 lbf on surface.
The minimum available set-down force is -2701 lbf at 5000 ft.



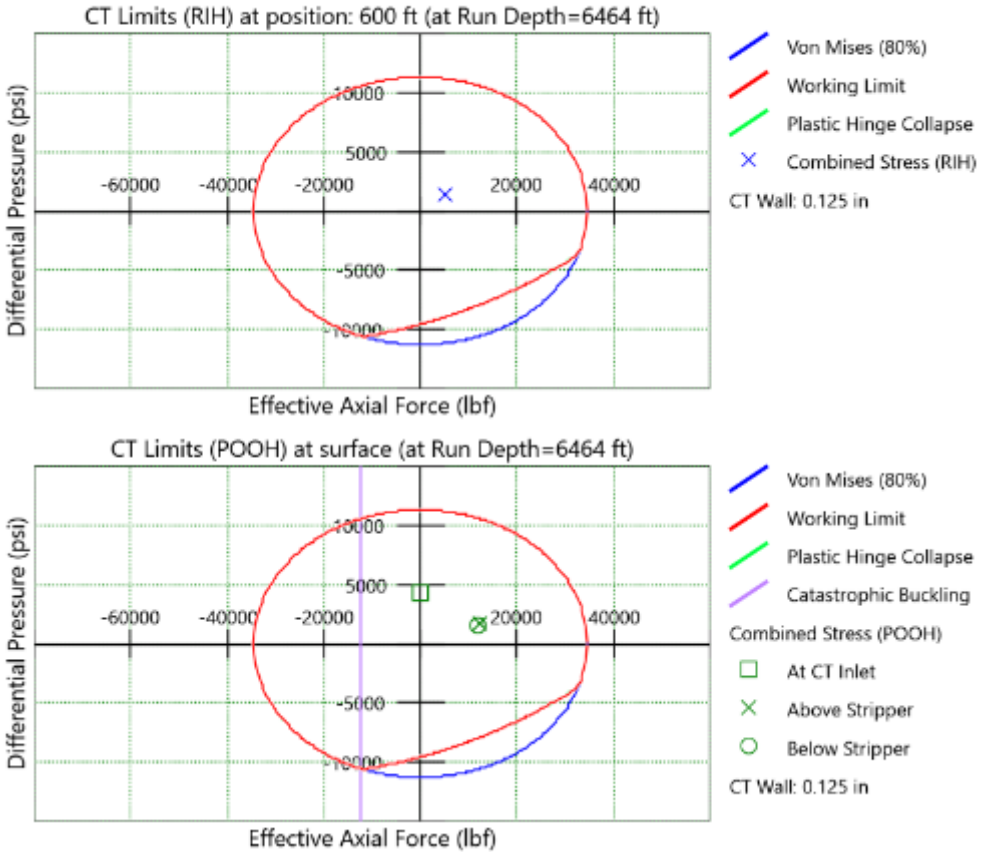
MAXIMUM STRING PICK UP LIMIT

MD1 The available pick-up at 6464 ft based on 80% of yield strength is 15317 lbf.
The weight indicator reading will then be 33857 lbf.

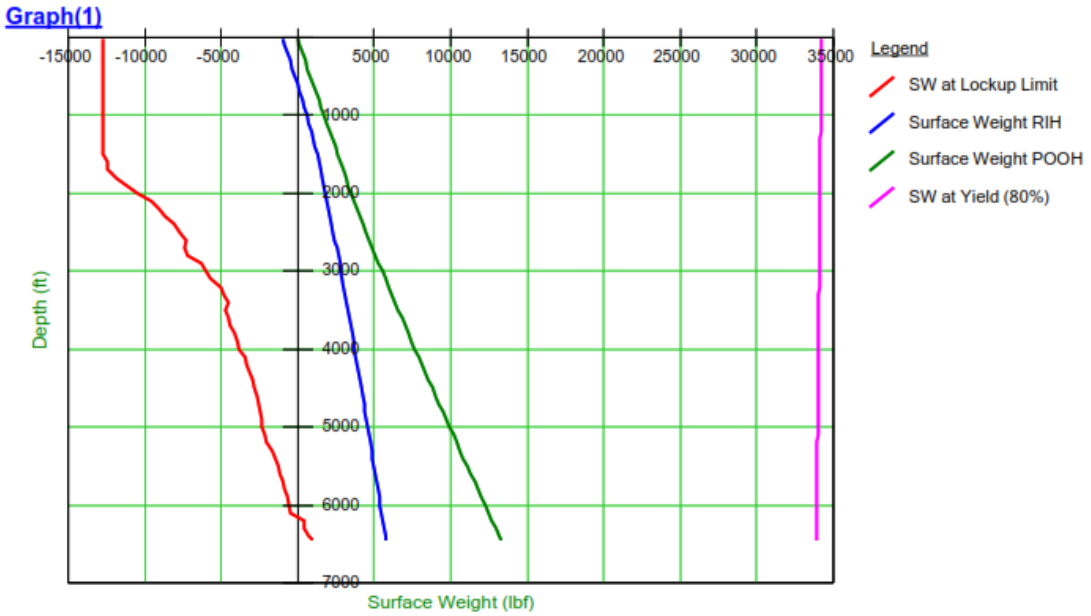


STRING LIMIT

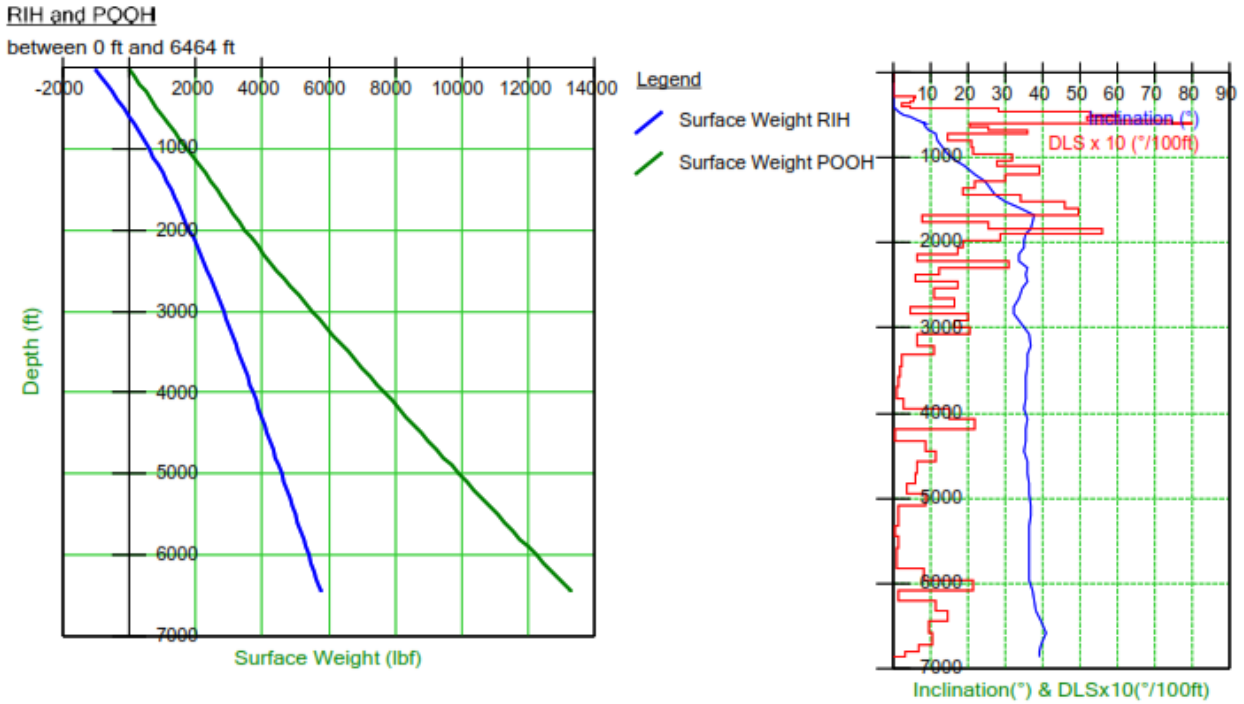
CT Limits



TUBING FORCE ANALYSIS (0.9 bpm of TIW & 400 scfm N2 with milling BHA)

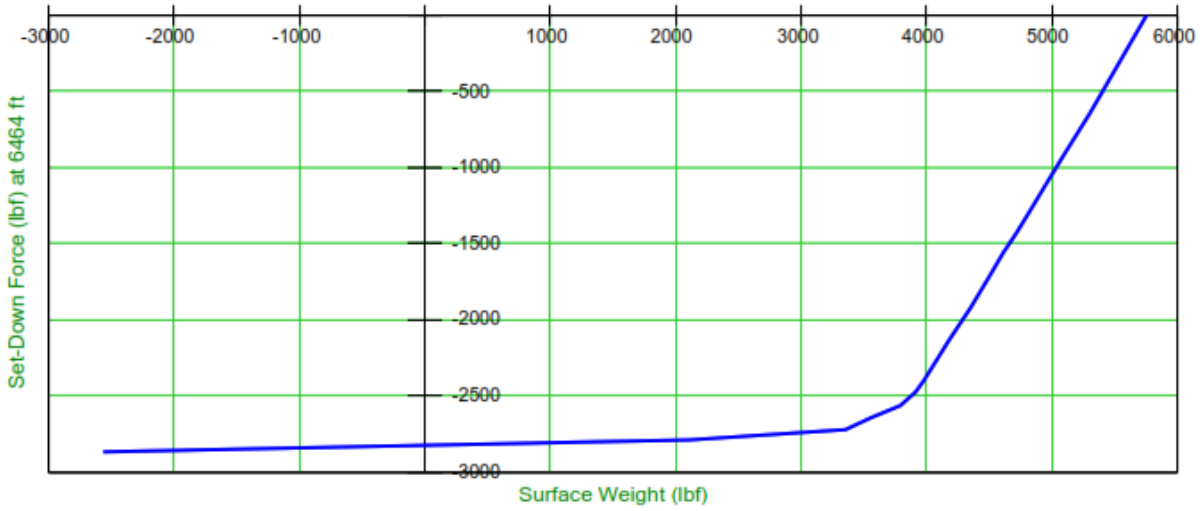


RIH & POOH WEIGHT



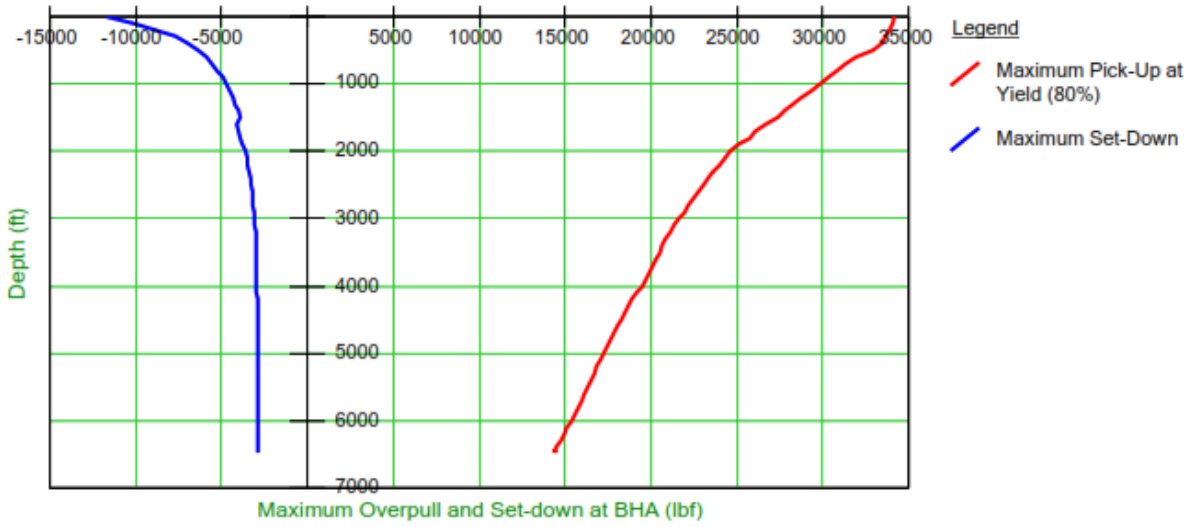
MAXIMUM STRING SET DOWN LIMIT

MD3 The available set-down force at 6464 ft is -2860 lbf at the end of the string.
The weight indicator reading will be 943 lbf on surface.
The minimum available set-down force is -2859 lbf at 6458 ft.



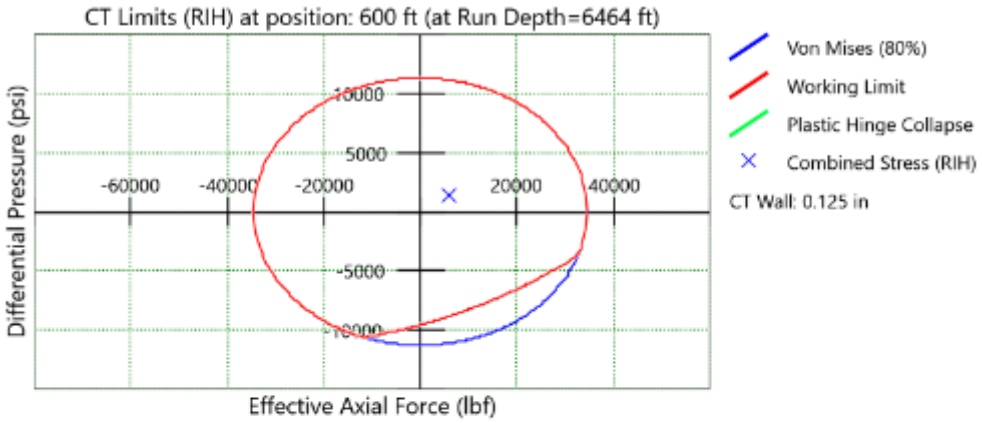
MAXIMUM STRING PICK UP LIMIT

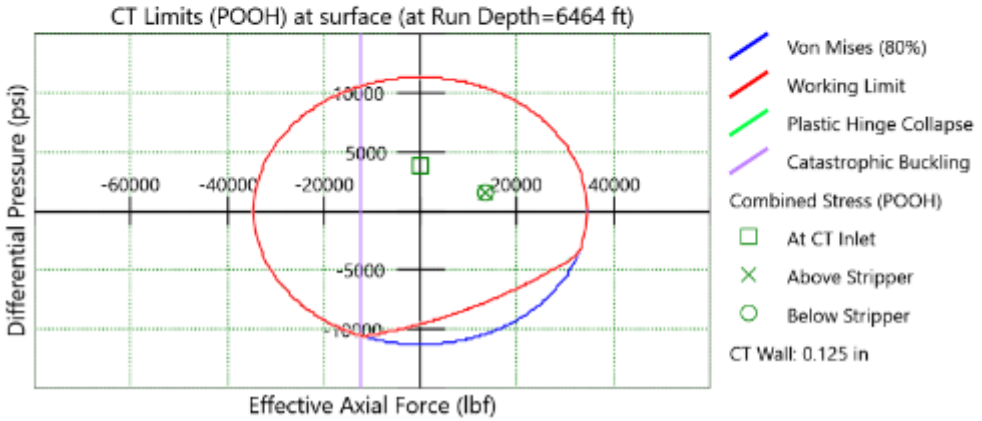
MD1 The available pick-up at 6464 ft based on 80% of yield strength is 14380 lbf.
The weight indicator reading will then be 33900 lbf.



STRING LIMIT

CT Limits



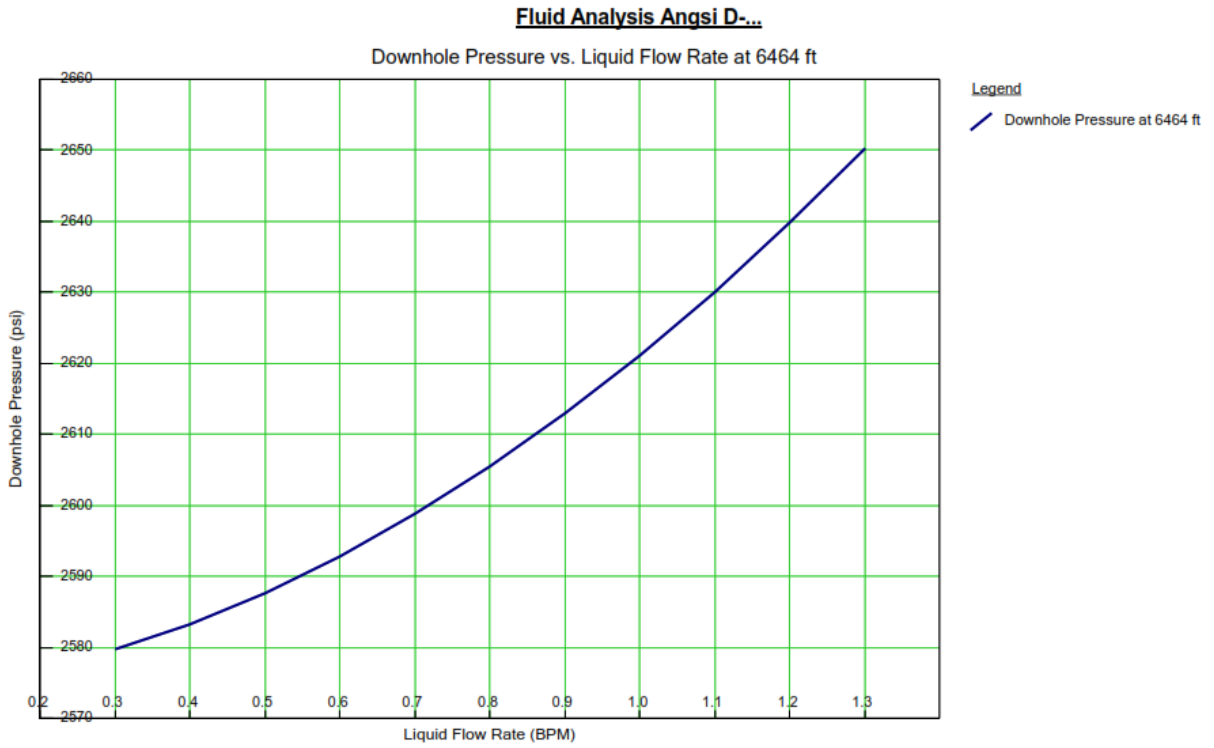


Summary of Maximum Set Down Weight & Maximum Pick Up Weight at EOT 1970-m MDDF

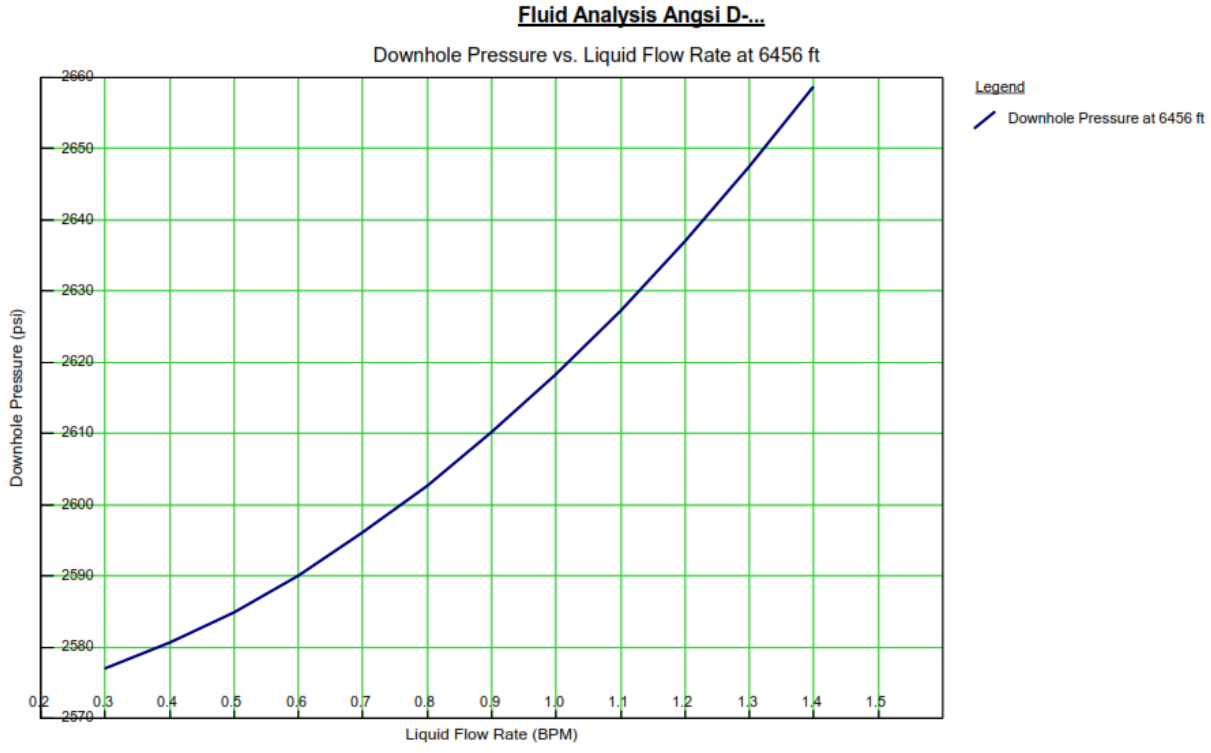
Parameter	Maximum set down weight (lbf)	Surface weight reading (lbf)	Maximum pick up weight (lbf)	Surface weight reading (lbf)
Idle rate at 0.3 bpm of TIW with SpinCat Nozzle	-2,756	367	15,439	34,241
High jetting rate at 1.2 bpm of TIW with SpinCat Nozzle	-2,710	240	15,244	33,706
Nitrified TIW (1.0 bpm of TIW & 300 scfm N2) with SpinCat Nozzle	-2,874	974	14,326	33,903
Max rate at 1.1 bpm of TIW with milling BHA	-2,708	261	15,317	33,857
Nitrified TIW (0.9 bpm of TIW & 400 scfm N2) with milling BHA	-2,860	943	14,380	33,900

APPENDIX VI – HYDRA & CLEANOUT SIMULATIONS

FLUID ANALYSIS WITH SPINCAT NOZZLE



FLUID ANALYSIS WITH MILLING BHA



CLEANOUT ANALYSIS

SCO Angsi D-04S with TIW (1946m WLTHF)

Solids Removal Procedures

No.	Event	Event Time	Procedure Description
1	RIH	3h 32m 50s	RIH to 6385 ft at 30.0 ft/min. Pump "Sea Water" at 0.5 BPM while maintaining 150 psi well head pressure.
2	CLEANING (Fill Penetrating)	0h 3m 0s	Penetrate fill to 6415 ft to 10.0 ft/min. Pump "Sea Water" at 1.0 BPM while maintaining 150 psi well head pressure.
3	CLEANING (Wiper Trip Up)	0h 41m 30s	Pull CT back to 6000 ft at 10.0 ft/min. Pump "Sea Water" at 1.0 BPM while maintaining 150 psi well head pressure.
4	CLEANING (Circulation)	0h 41m 30s	Circulate 41.5 bbls of "Sea Water" at 1.0 BPM while CT stays at the wiper pullback depth of 6000 ft
5	CLEANING (Wiper Trip Dn)	0h 41m 30s	Run CT back to 6415 ft at 10.0 ft/min. Pump "Sea Water" at 1.0 BPM while maintaining 150 psi well head pressure.
6	CLEANING (Fill Penetrating)	0h 3m 0s	Penetrate fill to 6445 ft to 10.0 ft/min. Pump "Sea Water" at 1.0 BPM while maintaining 150 psi well head pressure.
7	CLEANING (Wiper Trip Up)	0h 44m 30s	Pull CT back to 6000 ft at 10.0 ft/min. Pump "Sea Water" at 1.0 BPM while maintaining 150 psi well head pressure.
8	CLEANING (Circulation)	0h 41m 30s	Circulate 41.5 bbls of "Sea Water" at 1.0 BPM while CT stays at the wiper pullback depth of 6000 ft
9	CLEANING (Wiper Trip Dn)	0h 44m 30s	Run CT back to 6445 ft at 10.0 ft/min. Pump "Sea Water" at 1.0 BPM while maintaining 150 psi well head pressure.
10	CLEANING (Fill Penetrating)	0h 1m 54s	Penetrate fill to 6464 ft to 10.0 ft/min. Pump "Sea Water" at 1.0 BPM while maintaining 150 psi well head pressure.
11	CLEANING (Wiper Trip Up)	0h 46m 24s	Pull CT back to 6000 ft at 10.0 ft/min. Pump "Sea Water" at 1.0 BPM while maintaining 150 psi well head pressure.
12	CLEANING (Circulation)	0h 41m 30s	Circulate 41.5 bbls of "Sea Water" at 1.0 BPM while CT stays at the wiper pullback depth of 6000 ft
13	POOH	3h 20m 0s	POOH to surface from 6000 ft at 30.0 ft/min. Pump "Sea Water" at 0.5 BPM while maintaining 150 psi well head pressure.

SCO Angsi D-04S with TIW (1946m WLTHF)

Solids Removal Stage Data

No.	Event	Stage Time hh:mm:s	Elapsed Time hh:mm:s	CT Depth (ft)	Pump Press. (psi)	Pumping Fluid	Pump Rate (BPM)	Solids Conc. (lb/gal)	BHP (psi)	CT Speed (ft/min)	Fill Lifted (ft)	Cum. Fill Lifted (ft)	Fluid Volume (bbls)	Cum. Fluid Volume (bbls)	Min. Ann. Velocity (ft/min)
1	RIH	03:32:50	03:32:50	6385	1032	Sea Water	0.5	0	2621	30	0	0	106.4	106.4	76.8
2	Penetrating	00:03:00	03:35:50	6415	3486	Sea Water	1	0.054	2672	10	30	30	3	109.4	153.6
3	Wiper Trip Up	00:41:30	04:17:20	6000	3494	Sea Water	1	0.054	2668	10	0	30	41.5	150.9	153.6
4	Circulation	00:41:30	04:58:50	6000	3488	Sea Water	1	0	2662	0	0	30	41.5	192.4	153.6
5	Wiper Trip Dn	00:41:30	05:40:20	6415	3479	Sea Water	1	0	2666	10	0	30	41.5	233.9	153.6
6	Penetrating	00:03:00	05:43:20	6445	3485	Sea Water	1	0.054	2672	10	30	60	3	236.9	153.6
7	Wiper Trip Up	00:44:30	06:27:50	6000	3494	Sea Water	1	0.054	2668	10	0	60	44.5	281.4	153.6
8	Circulation	00:41:30	07:09:19	6000	3488	Sea Water	1	0	2662	0	0	60	41.5	322.9	153.6
9	Wiper Trip Dn	00:44:30	07:53:49	6445	3479	Sea Water	1	0	2666	10	0	60	44.5	367.4	153.6
10	Penetrating	00:01:54	07:55:43	6464	3486	Sea Water	1	0.064	2674	10	19	79	1.9	369.3	14.1
11	Wiper Trip Up	00:46:24	08:42:07	6000	3495	Sea Water	1	0.064	2669	10	0	79	46.4	415.7	153.6
12	Circulation	00:41:30	09:23:37	6000	3488	Sea Water	1	0	2662	0	0	79	41.5	457.2	153.6
13	POOH	03:20:00	12:43:37	6000	1034	Sea Water	0.5	0	2620	30	0	79	100	557.2	76.8

APPENDIX V – 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.

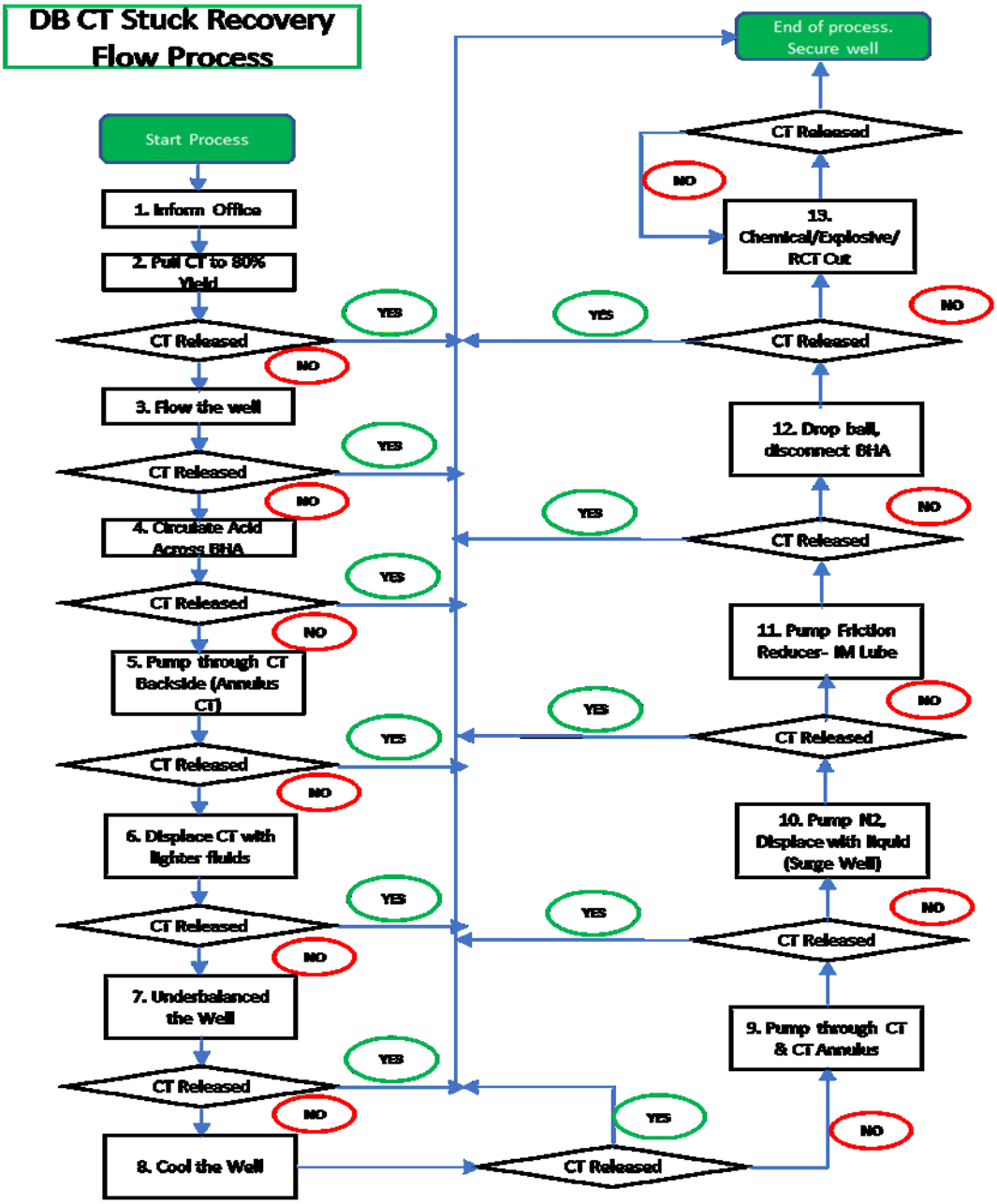
The following are options that may be appropriate depending on the particular circumstances:

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 FATIGUE 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.

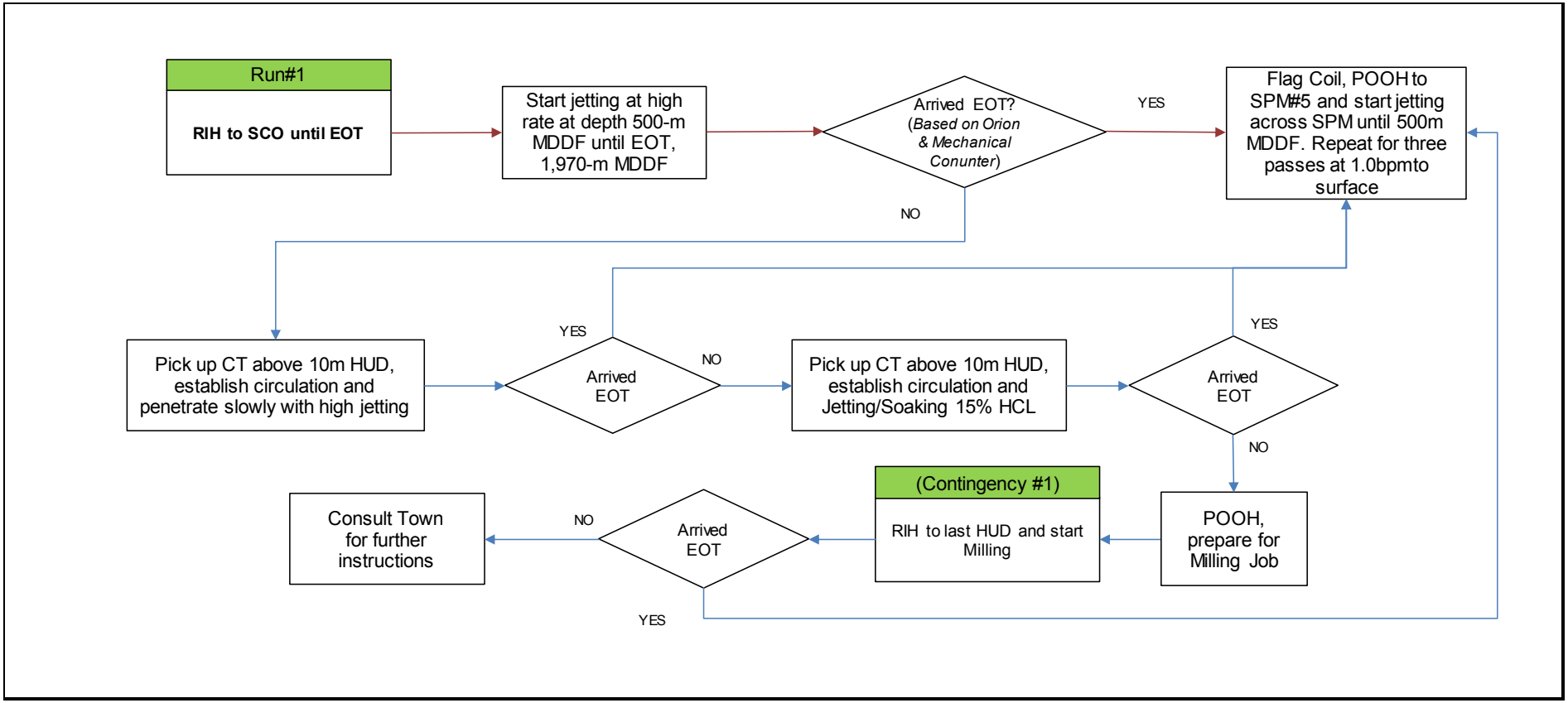
STUCK CT COIL RECOVERY PROCESS

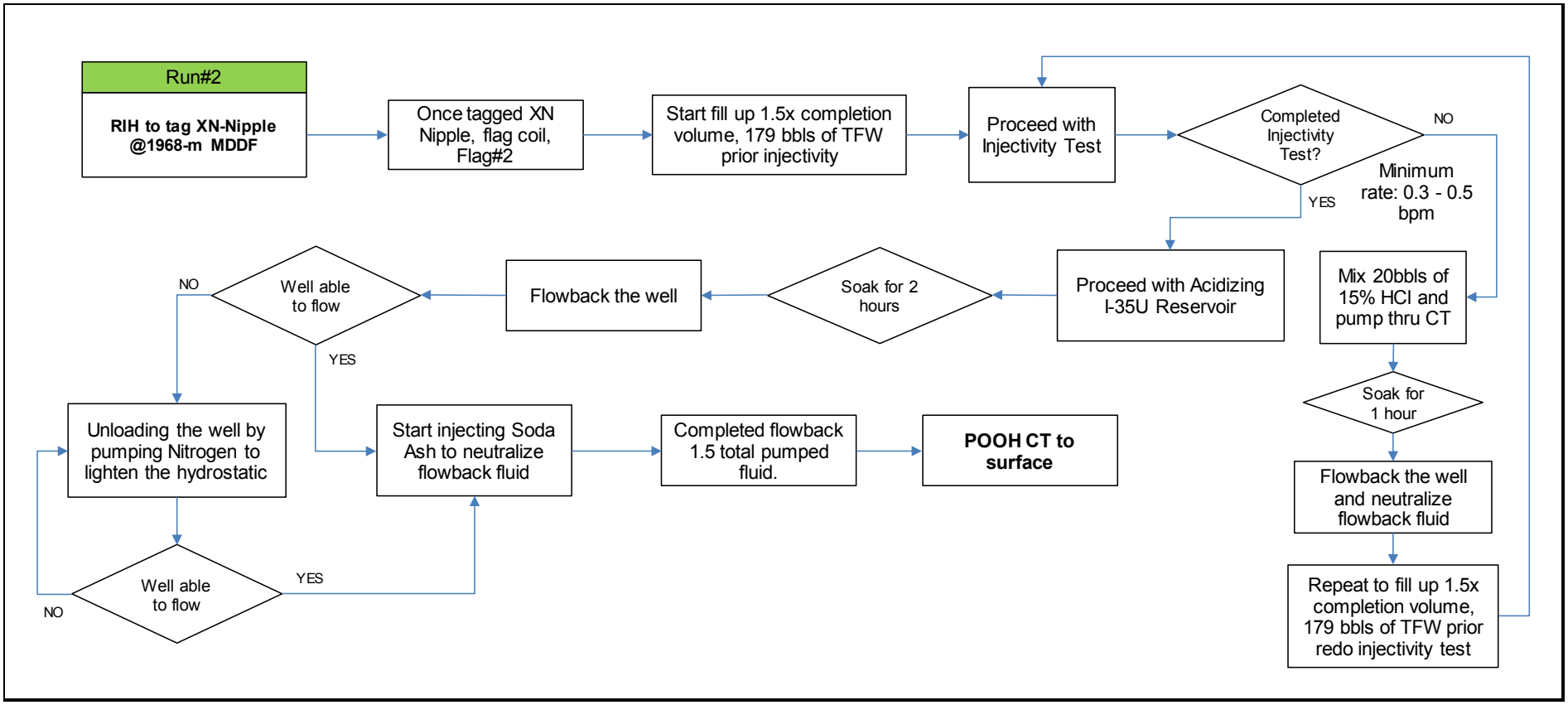


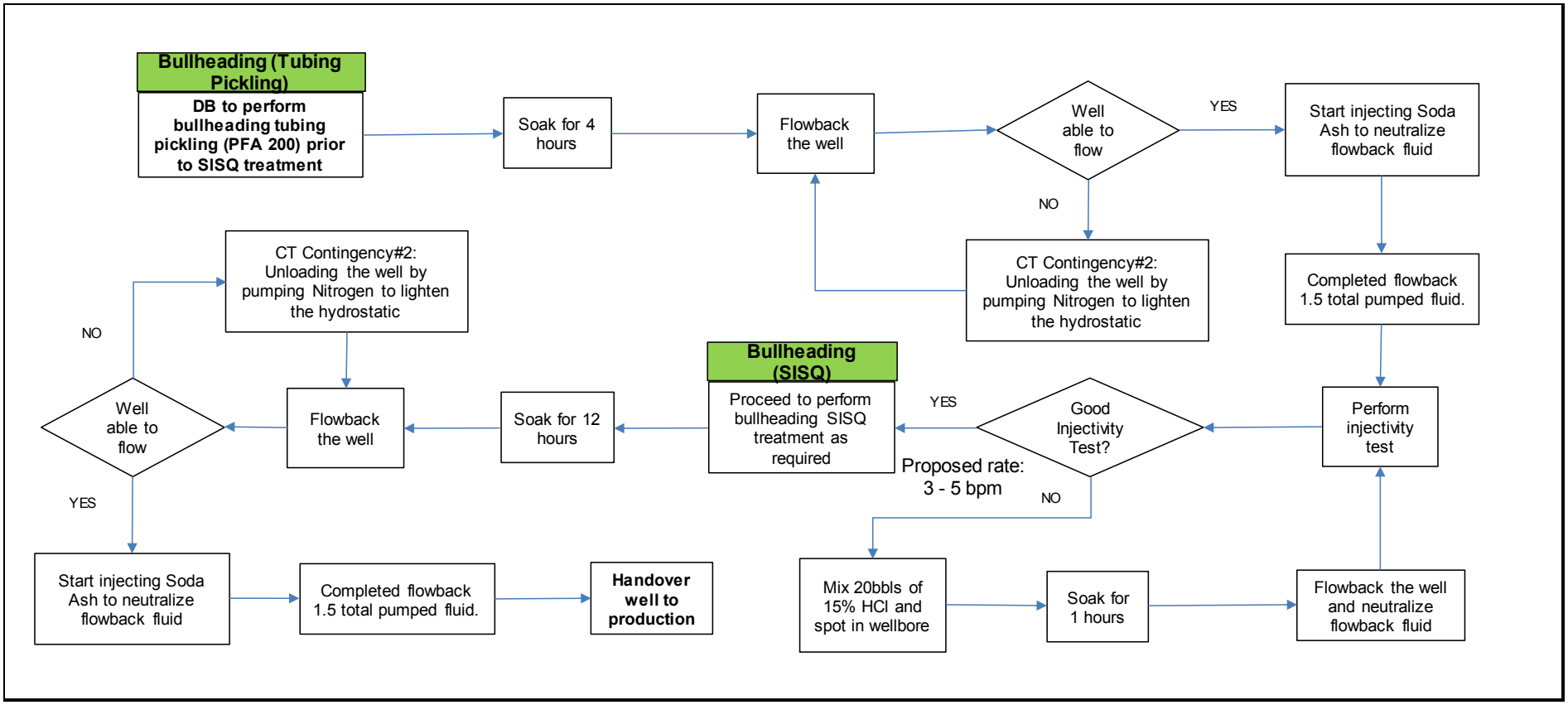
Precautionary Steps to avoid Stuck while Cleanout in Dual string Completion:

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 VI – DECISSION TREE




Run#2
RIH to tag XN-Nipple @1968-m MDDF
Once tagged XN Nipple, flag coil, Flag#2
Start fill up 1.5x completion volume, 179 bbls of TFW prior injectivity
Proceed with Injectivity Test
Completed Injectivity Test?
NO
YES
Minimum rate: 0.3 - 0.5 bpm
Proceed with Acidizing I-35U Reservoir
Soak for 2 hours
Flowback the well
Well able to flow
NO
YES
Unloading the well by pumping Nitrogen to lighten the hydrostatic
Well able to flow
NO
YES
Start injecting Soda Ash to neutralize flowback fluid
Completed flowback 1.5 total pumped fluid.
POOH CT to surface
Mix 20bbls of 15% HCl and pump thru CT
Soak for 1 hour
Flowback the well and neutralize flowback fluid
Repeat to fill up 1.5x completion volume, 179 bbls of TFW prior redo injectivity test


Bullheading (Tubing Pickling)
DB to perform bullheading tubing pickling (PFA 200) prior to SISQ treatment
Soak for 4 hours
Flowback the well
Well able to flow
YES
Start injecting Soda Ash to neutralize flowback fluid
NO
CT Contingency#2: Unloading the well by pumping Nitrogen to lighten the hydrostatic
Completed flowback 1.5 total pumped fluid.
CT Contingency#2: Unloading the well by pumping Nitrogen to lighten the hydrostatic
NO
Well able to flow
Flowback the well
Soak for 12 hours
Bullheading (SISQ)
Proceed to perform bullheading SISQ treatment as required
YES
Good Injectivity Test?
Perform injectivity test
Proposed rate: 3 - 5 bpm
NO
YES
Start injecting Soda Ash to neutralize flowback fluid
Completed flowback 1.5 total pumped fluid.
Handover well to production
Mix 20bbls of 15% HCl and spot in wellbore
Soak for 1 hours
Flowback the well and neutralize flowback fluid

APPENDIX VII – SISQ PROPOSAL

Technical Proposal

Scale Inhibitor Squeeze

For PETRONAS PCSB – D04 SS ANGSI

Date: 27th April 2022 (R1)

Confidential

Baker Hughes

Project Details

Project Detail	
Purpose:	To propose a scale inhibitor squeeze treatment for Angsi well D04 SS
Clarity ID:	
Key Words:	Scale Squeeze, PETRONAS, ANGSI

Personnel	
Project Sponsors:	Abdullah Othman
Authors:	Mohd Amri Mohd, Mohamed Farouk Ibrahim,
Contributors:	
Reviewers:	Abdullah Othman, Damien Clover

Distribution			
Baker Hughes:	Abdullah Othman	Damien Clover	Mohd Amri Mohd
	Farouk Ibrahim		
Customer:	Aziz M Tahir	Azri Khairudin	Izyan Haziqah
	M Syakir B M Nawi	M Syamil M Adib	Luqman Hakim

Rev	Date	Description	By	Approved
0	11th April 2022	Initial Draft	MAM & MFI	DC & AO
1	27th April 2022	Rev. 1	MAM & MFI	DC & AO
2				
3				
4				
5				
5				

Table of Contents

1. Executive Summary

Baker Hughes Company (BKR) was given an extended opportunity by PETRONAS Carigali Sdn Bhd (PCSB) to provide a technical proposal to assess Scale Inhibitor Squeeze (SISQ) treatment for Angsi well(s). One Angsi well was listed as a new candidate for the scale inhibitor squeeze treatment; D04 SS. This well is a dual string oil producer with two producing zones, which is from zone I35U and I35L.

The main objective is to deploy a scale inhibitor scale squeeze treatment for D04 SS. Thus, inhibit further scale deposition in the production tubing as well as in the reservoir formation based on the designed treatment lifetime for 2 years.

The following work scope and associated Cost-Time-Resource (CTR) proposal has been prepared to define the activities to be completed by BKR to perform a detailed review scale squeeze treatment as a solution for scale mitigation.

2. Objective

To propose a scale inhibitor squeeze treatment for Angsi wells; D04 SS

3. Well Background

Data was gathered from PCSB prior SISQ technical proposal development. Based on table below, a specific targeted reservoir (I-35U) was identified for the SISQ treatment. Please refer to Appendix 1 for detailed well diagram.

Based on recent discussion with PCSB, there was a behind casing cross flow HPT-SNL detected back in March 2017. As per request by PCSB, BKR were asked to propose an increase treatment volume to 10% and 20% contingency pumping volume to compensate the volume loss (not squeeze into I-35U).

3.1 Angsi D04 SS Parameter

Table 1: Angsi SISQ candidate well parameters

Well Parameters	D04 SS
Reservoir	I-35U Southwest
Tubing String	Short string, 3-1/2" L80 tubing
Zone Depth (mMDDF)	10.5m
Bottom Hole Pressure (BHP)	2173 psig
Bottom Hole Temperature (BHT)	117.2 °C (243 °F)
Porosity (%)	28%
Permeability	600 mD (arithmetic average)
Max Angle	40°
Type of Completion	Dual string oil producer, 3-1/2" L80 tubing in 9-5/8" L80 casing
Frac Pressure	0.7 psi/ft
Water Production Rate (BWPD)	1,600 bwpd

4. Scale Clean-up

BKR highly recommended PCSB to perform tubing scale clean-up prior squeeze treatment to ensure adsorption efficiency of squeezed scale inhibitor is at optimum contact with reservoir rock surfaces. BKR chemical options available:

1. CND600 – To dissolve organic deposition (well restore)
2. SRW4811 – To dissolve Calcite scales
3. SRW83510 – To dissolve Barite scales
4. WAW85202– Mutual Solvent (for preflush)

5. Scale Squeeze (SISQ) Treatment

The main objective of scale inhibitor squeeze treatment is to increase the reservoir lifetime in order to avoid any loss of production by inhibiting mineral scale formation in the near wellbore, perforations and the tubular.

The squeeze technique involves the injection of a concentrated treatment pill of scale inhibitor into the formation by bull heading down the production tubing. The inhibitor is displaced into the formation to a predetermined distance from the wellbore by over-flushing with neutral brine. After soaking period in which the scale inhibitor adsorbs onto the formation rocks, the well is returned to production. The success of the treatment depends on the rate of the scale inhibitor flowing back from the produced water. This is confirmed by monitoring the produced water post squeeze samples. These results will be further analyzed for its Scale Inhibitor (SI) residual and inhibitor return profile can be plotted.

A scale squeeze treatment typically consists of five stages:

Stage	Treatment	Details
1	Preflush	Preflush plays a role in cools the near wellbore and conditions the rock surface.
2	Main Treatment	Injects the main scale inhibitor pill into the formation at a specific concentration (typically 5 to 20%); quantity of product is dependent upon scaling severity and water production.
3	Overflush	Deploys scale inhibitor into an appropriate location further inside the formation, i.e. push the main chemical pill reaches a desired squeeze radius. The tubing displacement fluids should be chosen with care so that the hydrostatic head caused by the fluid in the tubing column is not greater than the BHP. This should be checked and verified by PCSB prior to squeeze.
4	Shut in	It is typically between 12-24 hours to allow scale inhibitor adequately adsorb/precipitate in the formation.

5	Flowback and Monitoring	After the shut-in period the well is flow back and sampled for scale inhibitor residual monitoring. It is essential to develop a systematic post-job monitoring program to establish the field isotherm from first squeeze field data. When sufficient field return data is collected (a minimum of 30 scale inhibitor residual data throughout a period of time), it will then serve as a base case for subsequent squeeze optimization and further improvement upon re-squeeze.

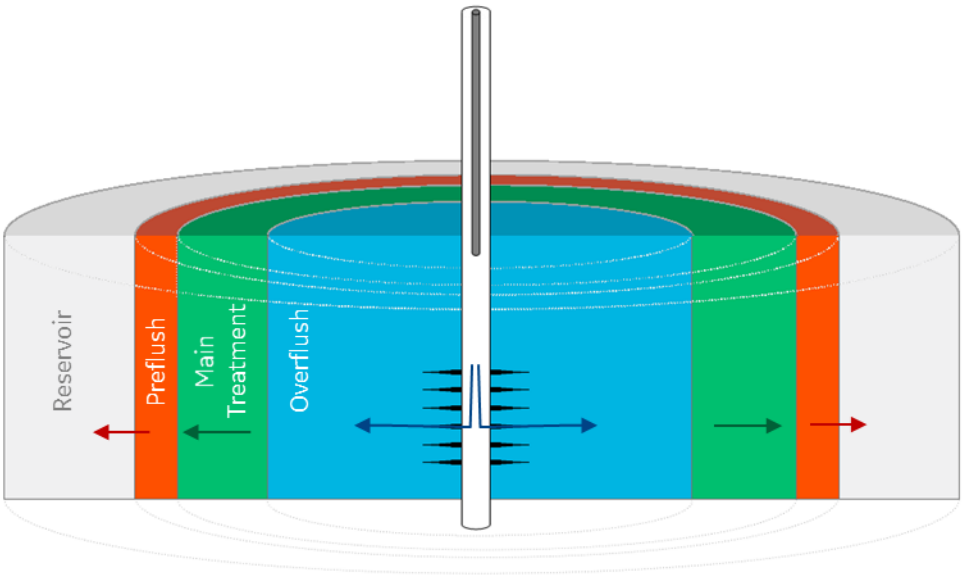


Figure 1: Scale Squeeze treatment visual in reservoir placement

6. Bull Heading Operations

The chemical pumping and Treated Sea Water (TSW) thru bull heading for SISQ program will be handled by PCSB's appointed pumping contractor. Baker Hughes (BKR) company representative will be on site to ensure:

1. QA/QC on the pre-mixed fluids
2. Ensure continuous pumping operations to be carried out by the pumping contractor
3. Confirm squeeze sequences and type of chemicals used for each stage
4. Chemical concentrations to be injected
5. Pre SISQ sampling and testing
6. Post SISQ sampling and testing

The onsite BKR rep will do sampling for the pre-mixed fluids on a regular basis and measure specific gravity of the solutions being injected. Prior to SISQ field application, BKR rep will prepare calibration sample using neat scale inhibitor diluted to the application concentration in filtered and treated seawater.

The scale inhibitor package comprising of pre-flush, main treatment and post-flush will be bull-headed into the well. Mixing of chemicals with filtered and treated sea water (TSW) will be pumped on the fly. Other method is to prepare pre-mixed in the batch mixer before pumping.

7. Coiled Tubing Unit Operations

The chemical pumping and Treated Sea Water (TSW) coiled tubing unit (CTU) for SISQ program will be handled by PCSB's appointed pumping contractor.

Baker Hughes scope is the same as above mentioned in bull heading operations. Eg sampling, testing, calibration and onsite support.

Chemical pumping volume will be the same, may differ on pumping rate 3-5bpm depending CTU capability.

8. Operation Summary

Baker Hughes scale squeeze treatment chemicals will be bull-headed down thru tubing as per pre-designed program. Alternatively, we can opt for coiled tubing squeeze deployment. One of the benefits of using a coiled tubing unit is that scale inhibitor is injected into targeted zone and it provides better placement as well as prolong the squeeze treatment lifetime.

Again, we **strongly recommend** that inorganic scale clean-out to be carried out prior to scale inhibitor scale squeeze treatment. This is to ensure production tubing is clear of inorganic scales obstruction in order to give optimum treatment performance.

Baker Hughes is able to provide integrated services to include pumping package, scale squeeze chemical package and qualified personnel to facilitate the treatment and subsequent post-job monitoring upon request.

It is essential to develop a systematic post-job monitoring program to establish the field isotherm from first squeeze field data. When sufficient field return data is collected (a minimum of 30 field data is recommended), it will then serve as a base case for subsequent squeeze optimization and further improvement upon re-squeeze.

9. Safety Operation Procedures

Prior to commencement of bull-heading and/or coiled tubing operations a pre-job meeting will be held. This should be attended by, as a minimum:

1. The CSR in charge
2. The Well Services Supervisor
3. The Baker Hughes Upstream Chemicals Supervisor
4. Representative of other involved service companies
5. Others as necessary

Safety meetings should be held at the start of every shift and risk assessments should be evaluated during this time. Tool box talk should be held immediately prior to job execution. Note: The safety meeting must be run by Baker Hughes Upstream Chemicals Supervisor addressing the following topics as a minimum:

1. Describe the job objective, fluids and volume to be pumped, pressure expected during the job and others
2. Personnel responsibilities throughout the job
3. Spills, fire, blow out, unexpected well behaviour
4. Muster point
5. Emergency shower station and eye wash station location
6. Working in height precaution (if any)
7. Trap potential energy such as pressure
8. Take name list of personnel on site for head count
9. Review risk assessment and job safety analysis (JSA)
10. Discuss the well H_2S, CO_2, Hg (Mercury) content (if any)
11. Emergency responses
12. Include other item for discussion
13. Permit To Work application

Health, Safety & Environment

1. Describe the job objective, fluids and volume to be pumped, pressure expected during the job and others
2. Evaluate possible risk to arise during the job execution
3. 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
4. Review MSDS of each product that will be used. Verify that all personnel on location handling toxic or corrosive products have the proper PPE
5. Review the contingency plan for spills
6. Other topics to be included

10. Squeeze Design and Treatment Volume

10.1 D04 SS

Using flowback field data from B15, Baker Hughes able to derive an adsorption isotherm for D04 SS. SQUEEZE computer simulation analysis was run to predict the squeeze life of the product and to develop an optimal squeeze design for the target well.

The squeeze treatment is design in such a way to protect the producing reservoir from scale formation for a desired period. However, it is very much dependent on the amount of water the well produces (cumulative water rate). If the well is producing more water than the water rate anticipated during the design stage, shorter treatment lifetime shall be expected.

At the initial design stage, data gathering was performed and the design parameters were identified. BKR used an adsorption isotherm derived from B15 well (1-35L) to calculate the amount of chemical needed for D04 SS.

Table 1: Well parameters

Well Parameters	D04 SS
Reservoir	I-35U Southwest
Tubing String	Short string, 3-1/2" L80 tubing
Zone Depth (mMDDF)	10.5m
Bottom Hole Pressure (BHP)	2173 psig
Bottom Hole Temperature (BHT)	117.2 °C (243 °F)
Porosity (%)	28%
Permeability	600 mD (arithmetic average)
Max Angle	40°
Type of Completion	Dual string oil producer, 3-1/2" L80 tubing in 9-5/8" L80 casing
Frac Pressure	0.7 psi/ft
Water Production Rate (BWPD)	1,600 bwpd

Table 2: Scale Squeeze target treatment parameters

Parameters	D04 SS
Minimum Inhibitor Concentration (MIC)	5 ppm
Protection Days	730 days
Water Production Rate	1,600 bwpd

Table 3: Scale Squeeze treatment design for D04 SS

Treatment	D04 SS	D04 SS (no MS)	D04 SS (10% contingency)	D04 SS (20% contingency)
Protection days	730 days	730 days	730 days	730 days
Mutual Solvent* (bbls)	10	N/A	10	10
Preflush (bbls)	50	50	50	50
Main Treatment (bbls)	600	600	660	720
Overflush (bbls)	1920	1920	2112	2304
Tubing Displacement	TBC	TBC	TBC	TBC
Shut in (hours)	12	12	12	12
Radial Penetration (ft)	22ft	22ft	22.8ft	23.9
No of SCW82451 drums needed	50	50	55	60

Dynamic Scale Loop (DSL) testing was conducted using I-35L, results shown that the reservoir's minimum inhibitor concentration (MIC) is at 5ppm. Therefore, Scale Squeeze job replication program was design for 5ppm for two years protection respected to individual well water production rate.

11. Monitoring Program

11.1 Sampling Schedule

Below is the sampling schedule plan for flowback samples.

DAY	MONTH	WEEK	Date	Time(hrs)	Sample Description	Volume	Accumulated (bbls)		Qty (For Baker)	Collected By	Date sample is delivered to KSB	MTF No.	Sample ID	
							Oil	Water					BHI	Status
1	MT1	WK1			Produced Water	250			24	BHI				
2					Produced Water	250			1	BHI				
					Produced Water	250			1	BHI				
3					Produced Water	250			1	BHI				
					Produced Water	250			1	BHI				
4					Produced Water	250			1	BHI				
					Produced Water	250			1	BHI				
5					Produced Water	250			1	BHI				
					Produced Water	250			1	BHI				
6					Produced Water	250			1	BHI				
					Produced Water	250			1	BHI				
7					Produced Water	250			1	BHI				
					Produced Water	250			1	BHI				
9		WK2			Produced Water	250			1	PCSB				
13					Produced Water	250			1	PCSB				
16		WK3			Produced Water	250			1	PCSB				
20					Produced Water	250			1	PCSB				
23		WK4			Produced Water	250			1	PCSB				
27					Produced Water	250			1	PCSB				

Sampling to be conducted as per monitoring program provided.
Turnaround result will be 14 days after receiving samples.

11.2 Sampling Frequency

Attached below is the monitoring program for pre & post Squeeze treatment

Scale Squeeze Sampling Frequency and Tests									
	Sample	Day	Volume /ml	frequency	10 Ion	pH	Alkalinity	SI Residual	Total Number of Samples
Pre-Squeeze Samples									
	Produced Water	0	250	1	✓	✓	✓		1
	Pre -Flush	0	250	1				✓	1
	Main treatment	0	250	1				✓	1
	Post Flush	0	250	1					1
Post- Squeeze Treatment									
	Produced Fluids	Day 1	250	Every hour				✓	24
	Produced Fluids	Day 2 - 7	250	2 x per day				✓	12
	Produced Fluids	Wk 2 - Wk 4	250	2 x per week				✓	6
	Produced Fluids	Month 2	250	4 x per month				✓	4
	Produced Fluids	Month 3	250	2 x per month	✓	✓	✓	✓	2
	Produced Fluids	Month 4	250	2 x per month				✓	2
	Produced Fluids	Month 5	250	2 x per month				✓	2
	Produced Fluids	Month 6	250	2 x per month	✓	✓	✓	✓	2
Total									**58**

11.3 Sampling Procedure

Below is the sampling procedure for Scale Inhibitor Return Analysis by ICP.

Step	Description	Requirements
1	Flush sampling point for 2-3 minutes	Sampling pail
2	Collect crude oil sample directly into seperating funnel	Seperating Funnel
3	Allow produced water to settle at the bottom of funnel.	Retort Stand
4	Separate produced water out.	
5	Add 25ml or 10% of EDTA-Na solution into 250ml sampling bottle.	5% EDTA-Na Solution in Li Tracer
6	Fill sampling bottle upto 250ml of collected produced water.	250ml sampling bottles
7	Shake and mix well	
8	Label the sampling bottle with labels proovided and tag them accordingly	Sampling Labels
9	List down date, time, fluid description and sample tag no. in the monitoring check sheet provided.	Monitoring check sheet
10	Load the samples into provided sampling box and ship to the following address: **Baker Hughes(M) Sdn Bhd** **K-444 Taman Kemaman** **24000 Kemaman,** **Terengganu** **Attention: Amri-0139452753 / Fatin-0145455339 / Syikin - 0122135292**	Sampling Box

The sample point must be thoroughly purged prior to sampling to assure that the sample is representative of the flow in the system. Flushing of these sample points may only be directed to hazardous drains or to a suitable vessel for controlled disposal elsewhere.

It is extremely important that the water stabilisation is performed as quickly as possible after the fluids have been sampled. It is known that once the fluids have been drawn from the flowline and subsequently depressurised and cool, barium sulfate will precipitate very quickly.

12. Previous Lab Analysis

Baker Hughes had assessed two products, FORSA™ SCW82451 (SCW82451) and FORSA™ SCW28493 (SCW28493) in Angsi field for scale squeeze application. These 2 recommended scale inhibitors are designed for squeeze application with proven and excellent track record in Malaysia Basins. Please refer to proposal attachments/appendix for SDS and case history.

Scale inhibitor physical properties are tabulated in table below:

Table 4: Scale inhibitors physical properties

Scale Inhibitor Physical Properties	SCW82451
Density	1.211
pH	2.4 pH
Flash Point	93.3°C

Both scale inhibitor are a phosphonate based scale inhibitor which is capable to inhibit calcite and barite scales.

12.1 Thermal Stability

Thermal stability was determined by placing the samples in an oven set at 120°C. A small amount of nitrogen pressure was applied to prevent the solutions from boiling. An observation, pH and FTIR were recorded before and after testing to determine of there were any changes. The parameters for this testing are outlined in Table 9.

Table 9: Experimental parameters for thermal stability testing

Parameter	Value
Temperature	120°C
Pressure	50 psi nitrogen
Duration	7 and 30 days
Products	SCW82451, SCW28493
Concentrations	Neat
Brine	n/a

The observations for the testing is presented in Table 10 and 11 below.

Table 10: Observations for SCW82451 after thermal stability testing

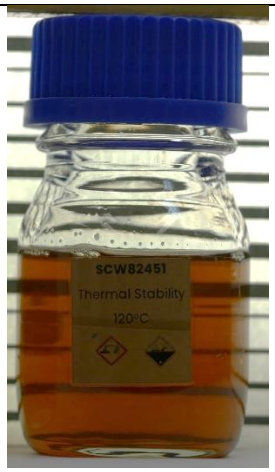
Parameter	Before Testing	After Testing
Observation	Clear, amber solution	Clear, amber solution
Image		
pH	2.3	2.4
FTIR % Match	99.8%	

Table 11: Observations for SCW28493 after thermal stability testing

Parameter	Before Testing	After Testing
Observation	Clear, amber solution.	Clear, amber solution
Image		
pH	4.13	4.2
FTIR % Match	99.6%	

No significant changes in both scale inhibitors chemical in thermal stability test and FTIR.

12.2 Material Compatibility

The pre-weighed metal coupons were immersed in solutions of the scale inhibitor and brine, then they were placed an oven set at 120°C. A small amount of nitrogen pressure was applied to prevent the solutions from boiling. The difference in weight after the testing period was used to determine the corrosion rate. The parameters for this testing are outlined in Table 22.

Table 22: Experimental parameters for compatibility with produced water, where SI denote scale inhibitor

Parameter	Value
Temperature	120°C
Pressure	50 psi nitrogen
Duration	7 days
Products	SCW82451, SCW28493
Concentrations	10% SI (as per Main Treatment)
Brine	Injection brine
Materials	Carbon steel C1018, stainless steel 316

The corrosion rates for the sample are in table below:

Table 23: Corrosion rates for materials compatibility for 10% solutions of SCW28493 and SCW82451.

Product	Material	Average Corrosion Rate (mm/y)	Rating
SCW28493	Carbon Steel C1018	1.436	C5
	Stainless Steel 316	0.005	C1
SCW82451	Carbon Steel C1018	1.865	C5
	Stainless Steel 316	0.000	C0

Rating scale:
C0 = <0.0025 mm/y no corrosion
C1 = 0.0025 – 0.025 mm/y very light corrosion
C2 = 0.025 – 0.125 mm/y light corrosion
C3 = 0.125 – 0.250 mm/y moderate corrosion
C4 = 0.250 – 0.500 mm/y heavy corrosion
C5 = >0.500 mm/y very heavy corrosion

13. Recommendation & Conclusion

Based on the successful treatment for well B15, PCSB had extended Squeeze replication study for Angsi field to well D04 SS.

Flowback data showed SCW82451 giving an excellent performance for Angsi reservoir. Based on previous DSL lab testing, SCW82451 MIC is set to 5ppm.

For this replication study for D04 SS, it is recommended to apply SCW82451 for Angsi wells for squeeze treatment based on designed pumping volume.

Thank you PETRONAS PCSB team for giving an extended opportunity to Baker Hughes on Angsi Scale Squeeze treatment study.

14. Appendix

14.1 Well Diagram – D04 SS

WELL NAME: ANGSI D4
LOCATION / SLOT: ANGSI D / 6

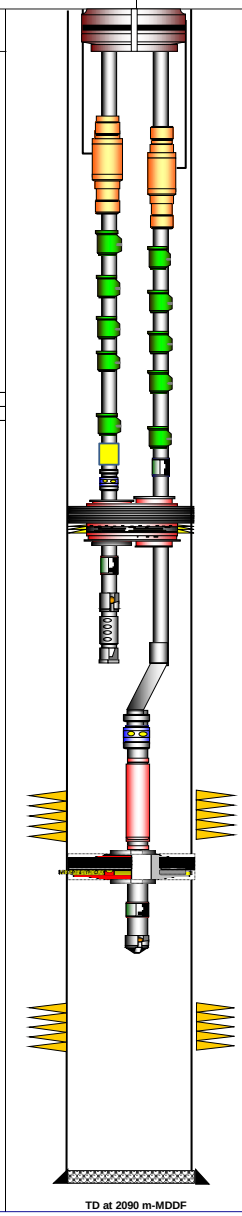
PROPOSED COMPLETION SCHEMATIC (DUAL STRING OIL PRODUCER)

DATE OF COMPLETION	:	Aug-09
RIG	:	T-10 (TADR)
TD	:	2090 m-MDDF
PBTD	:	2055 m-MDDF
MAXIMUM DEVIATION	:	40 deg
WATER DEPTH	:	68 m
DRILL FLOOR HEIGHT	:	33.89 m-AMSL
WELL HEAD	:	CAMERON
X-MAS TREE	:	CAMERON

Note: All depths are in meter from RKB to top of equipment.

		SIZE	WEIGHT	GRADE	THREAD	DEPTH
CONDUCTOR	:					
SURF. CASING	:					
INT. CASING	:					
CASING	:	9-5/8"	47 PPF	L-80	VAM TOP	990 m-MDD
LINER	:					
TUBING (LONG STRING)	:	3-1/2"	9.2 PPF	L-80	K-FOX	807 m-MDD
TUBING (SHORT STRING)	:	3-1/2"	9.2 PPF	L-80	K-FOX	775 m-MDD
COMPLETION FLUID	:	9.1 PPG NaCl (DRILL WATER + NaCl + 3% KCl) filtered to 30 NTU				
PACKER FLUID	:	9.1 PPG (3% NaCl + 0.2% BIOCIDE + 2% OXYGEN SCAVANGER + 2% CORROSION INHIBITOR)				

SHORT STRING (OIL PRODUCER) MAX OD IN	MIN ID IN	EQUIPMENT	Deviation Degree	DEPTH m-MDDF
3.920	2.880	FLOW COUPLING		
5.030	2.813	SCSSV-TRSV (Self Equalizing)		271
3.920	2.880	FLOW COUPLING		
5.360	2.867	SPM #1 DUMMY AUG 2021		567
5.360	2.867	SPM #2 DUMMY AUG 2021		749
5.360	2.867	SPM #3 (GLOV: 12/64")		873
5.360	2.867	SPM #4 (dummy)		1197
		PIP TAG #1		1807
		PIP TAG #2		1819
5.360	2.867	SPM #5 (dummy)		1838
4.000	2.992	RA SUB		1937
3.893	2.813	SLIDING SLEEVE DOOR CLOSED	40	1956
3.893	2.690	XN-NIPPLE (2.75")	40	1968
3.920	3.000	POP ASSEMBLY		1969
		PERFORATED PUP		
		CATCHER SUB		1970
		EOT		
			40	
I-35U OIL PRODUCER 1992 - 2002.5 MDDF (10.5m) 2300 psi/233 deg F 1599 m TVD SS				
			40	
		Sand Interval Difference : 5.5 m		
			40	
I-35 L OIL PRODUCER 2008 - 2014 MDDF (6m) 2300 psi/236 deg F 1663 m TVD SS				
		PBTD at 2055 m-MDDF		
		5/8" Float Collar at 2055m-MDDF		
		/8" Casing Shoe at 2085 m-MDDF		



TD at 2090 m-MDDF

DEPTH m-MDDF	LONG STRING (OIL PRODUCER) EQUIPMENT	MIN ID IN	MAX OD IN
	FLOW COUPLING	2.880	3.920
280	SCSSV-TRSV (Self Equalizing)	2.813	5.030
	FLOW COUPLING	2.880	3.920
576	SPM #1 (dummy)	2.867	5.360
768	SPM #2 (dummy)	2.867	5.360
892	SPM #3 (GLOV: 12/64")	2.867	5.360
1207	SPM #4 (dummy)	2.867	5.360
1847	SPM #5 (dummy)	2.867	5.360
1946	X-NIPPLE	2.813	4.550
1965	9-5/8" X 3-1/2" BHD PACKER (72 klbs pull on L/S to release)	2.880	8.230
1976	SLIDING SLEEVE DOOR CLOSED	2.813	3.893
	BLAST JOINT ± 5 METERS TOP AND BOTTOM	2.880	3.900
2001	leak identified HPT-SNL March 2017		
2004	9-5/8X 3-1/2" BHR PACKER	2.940	6.000
2005	Packer is holding		
2006	XN-NIPPLE (2.75") set plug April 2017	2.690	3.893
2007	POP ASSEMBLY	3.000	3.920
	EOT		
2014	Behind casing cross flow HPT-SNL Ma		
2025			
2085	9-5/8" CSG SHOE		

Update by: Sean Syazrul
Date: 7-May-13

14.2 Safety Data Sheet (SDS)

14.2.1 SDS SCW82451

MALAYSIA_ENGLISH_Oilfield_SCW82451

MALAYSIA_BAHASA MALAY_Oilfield_SCW

14.3 Case History

36835.Scale.Squeeze.Malaysia_Case.Hist