DIMENSION BID

PETRONAS

ANGSI A-24L
NITROGEN UNLOADING

Revision:	0
Prepared for:	M. Aizuki Nazwa A. Rahman
Date Prepared:	29th March 2023
Well:	A-24L
Field:	Angsi
Operation Region:	PMA
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DESIGN VERIFICATION

PREPARED BY DB CTS Field Engineer	Muhammad Ameerul Zaeem	29/3/2023 Date
REVIEWED BY DB CTS Technical Advisor	Kung Yee Han	29/3/2023 Date
APPROVED BY DB CTS Operation Manager	Aliff Amirul Adenan	29/3/2023 Date
APPROVED BY PCSB Angsi Well Intervention Engineer	M. Aizuki Nazwa A. Rahman	Date
APPROVED BY PCSB Technical Professional Well Intervention, PMA	M Izwan B A Jalil	Date
APPROVED BY PCSB Head of Cluster 1 Well Intervention, PMA	Ahmad Hafizi B Ahmad Zaini	Date

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

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REVISION HISTORY

Rev. No	Section	Date	Revised By
0	All	29/3/2023	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
TCC	Tubing Clearance Check
SGS	Static Gradient Survey

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OBJECTIVES

The objective of this job is to perform well unloading via Coiled Tubing (CT) to unload liquid held up inside completion tubing until across I-100 Perf Interval.

BACKGROUND

Angsi-A24 is a dual gas producer which was completed on Nov 2003 with maximum deviation of 69.22 degree at 1,123m MDDF. Currently the well is unable to flow post ESD in Aug 2022 and had high liquid level which reported at 3,000m MDDF with reservoir pressure reported at 700 psi (I-100) based on SGS conducted on November 2022. This job program details unloading wellbore fluid with N2 until across I-100 perforation section at 3,653 m / 11,985 ft MDDF.

WELL DATA

Input Parameter	Parameter Value
Field	Angsi-A24
Max. Deviation (degrees)	69.22 degree @ 1,123m MDDF
Min. Restriction (inch)	**2.69" (XN Nipple) @ 3,392.83m MDDF (Long String)**
Tubing Specification	3-1/2" Production Tubing, 9.2# ppf, 13Cr
Type of Fluid & Density	9.2 PPG NaCl (based on Completion Fluid data in Well Diagram)
Top of Fluid	3,000 m MDDF / 9,843 ft MDDF
Current Well Status	Idle
Depth of zone	I-100: 3,603m – 3,653m MDDF
Reservoir Pressure	700 psi
Reservoir Temperature	260 deg F
Porosity	18%
Permeability	161 mD
Fracture Gradient	0.70psi/ft
Additional Information / Notes / Special Requirement:	
• Top of fluid recorded by slickline during SGS at 3,000 m MDDF / 9,843 ft MDDF (Nov 2022) • Latest Slickline HUD at 3,656 m MDDF / 11,995 ft MDDF (Nov 2022)	

OPERATION SUMMARY

Item	*Job Description*	*Remark*
A	Slickline	1. RIH FOR TCC & SGS
B	CT Operation	1. RUN #1: N2 UNLOADING 2. CONTINGENCY RUN: N2 UNLOADING
C	Production	1. WELL MONITORING

WELL DIAGRAM

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

SHORT STRING
3-1/2", 9.2PPF, L-80 13-Cr, FOX

EQUIPMENT	MIN ID IN	MAX OD IN	DEPTH mMDDF
TUBING HANGER	2.823	11.000	16.98
FLOW COUPLING	2.992	4.150	
TR-SCSSSV	2.813	5.030	253.52
FLOW COUPLING	2.992	4.150	
X NIPPLE	2.813	3.960	594.21
X NIPPLE	2.813	3.960	3025.13
9 5/8" BHD DUAL PACI (S/S SET)	2.820	8.457	3054.29
XN- NIPPLE	2.690	3.960	3056.60
POP ASSY	2.871	3.970	3057.74
CATCHER SUB	-	3.920	3059.20
END OF TUBING			3059.37

WLD - Tubing Leaks
10.5, 18.7, 71.5m

Possible tubing leaks (>80%) penetration from MIT 26.4m, 2401.3m, 2416.6m, 2554.5m, 2654.4m, 2701.4m, 2763.8m

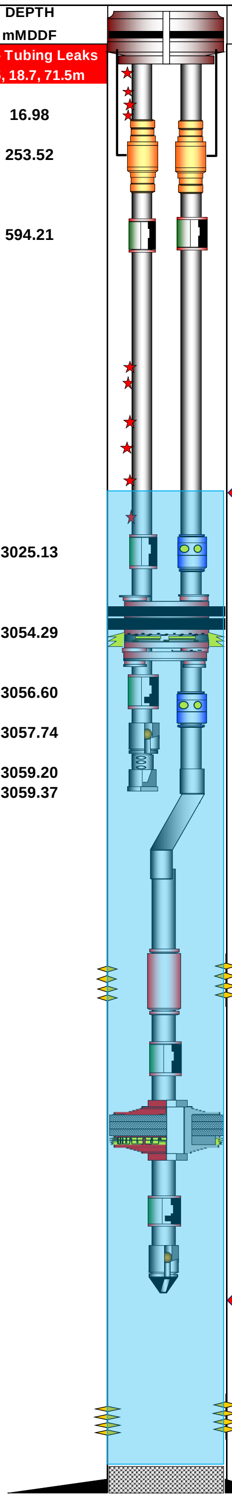
I - 35 RES FUTURE GAS PRODUCER

I - 68 RES WATER INJECTOR
3335.0 - 3351.0 mMDDF

I - 70 RES - FUTURE GAS PRODUCER

I - 100 RES - GAS PRODUCER
3603.0 - 3653.0 mMDDF

Last intervention
Apr 08 MIT



PBTD: 3749 mMDDF
TD: 3791 mMDDF

SINGLE STRING
3-1/2", 9.2PPF, L-80 13-Cr, FOX

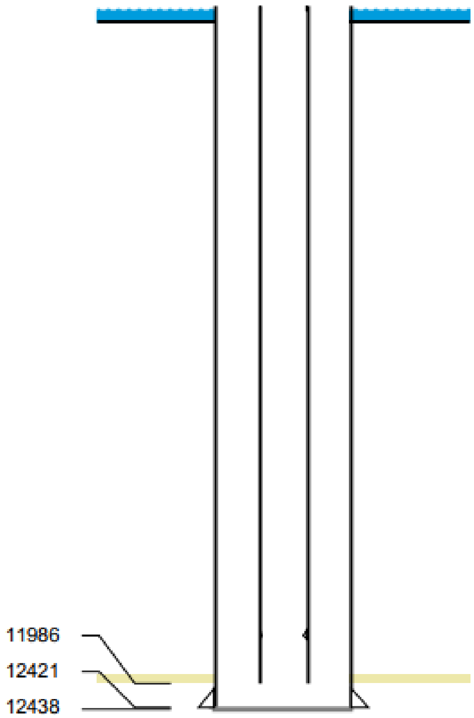
DEPTH mMDDF	DEV (°)	EQUIPMENT	MIN ID IN	MAX OD IN
16.98	0.3	TUBING HANGER	2.823	11.000
		FLOW COUPLING	2.992	4.150
162.74	14.1	TR-SCSSSV	2.813	5.030
		FLOW COUPLING	2.992	4.150
603.47	44.6	X NIPPLE	2.813	3.960
3034.34	63.8	XD-SSD (CLOSED)	2.813	4.550
3054.29	64.5	9 5/8" BHD DUAL PACK (S/S SET)	2.820	8.457
3084.70	64.8	XD-SSD (CLOSED)	2.813	4.550
	64.5			
3330.06	65.30	BLAST JOINT	2.880	4.115
3357.05	65.10			
3366.19	65.0	X-NIPPLE	2.813	3.960
3376.56	64.6	9-5/8" BHR HYD PKR	4.000	8.340
3392.83	64.0	XN NIPPLE	2.690	3.960
3653.08		POP ASSY	2.880	3.920
3653.25	60.1	END OF TUBING		
3786.0	58.6	9-5/8" CASING SHOE		

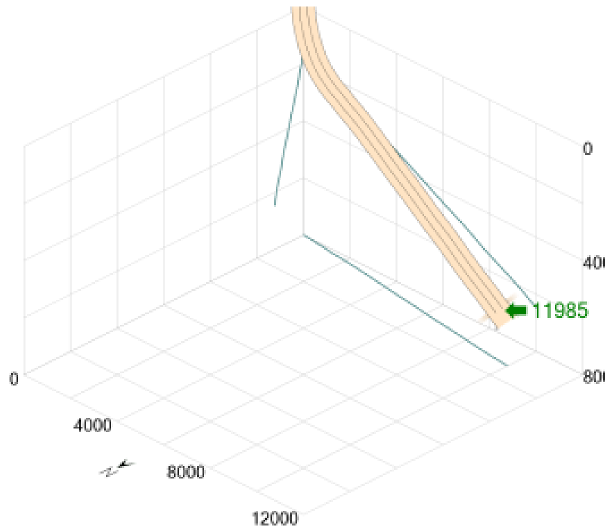
Fluid Level at 3,000 m MDDF (Nov 22)

Slickline HUD @ 3,656 m MDDF (Nov 22)

I - 100 RES - GAS PRODUCER
3603.0 - 3653.0 mMDDF

WELL 3D PLOT





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

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

COMPLETION VOLUME

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

Angsi A-24L **Downhole Calculation**

Prepared Date: 27/3/2023

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

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

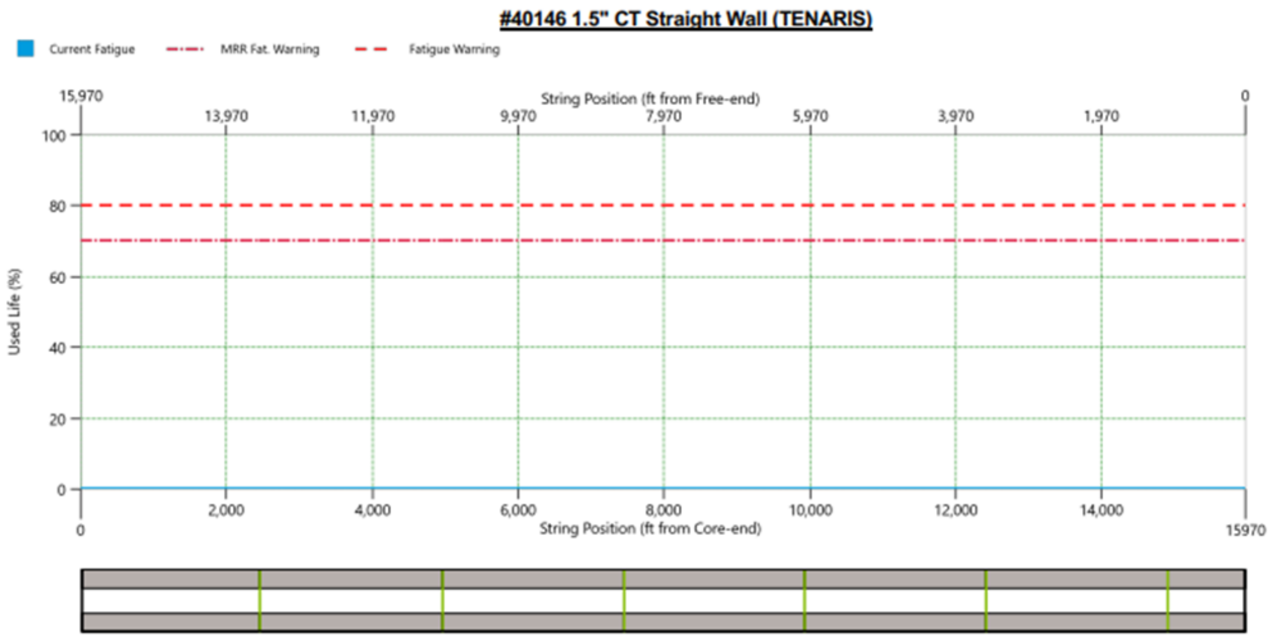
B-Annulus (PCP)																
Type	External Pipe			Internal Pipe			Internal Pipe			Caps	From	To	From	To	Length	Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	Barrel/lin (ft)	m	m	ft	ft	ft	
Packer #1 to EOT SS	9 5/8	8.835	40	3 1/2	2.992	9.2	3 1/2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

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

COILED TUBING STRING INFORMATION

OD (in)	Spec	W/T (in)	ID (in)	Length (ft)	Used Life
1.5	Tenaris HS-90	0.125	1.25	15,970	0.83%
CT Volume: 22.2 bbls					

CT STRING FATIGUE



CT STRING #40146 LATEST PIPE MANAGEMENT

Date	Job	CT External CI	CT Internal CI	CT leng	CT cut	New CT leng	Update by	CT purged with N2	CT plugged	Job Fatigue	Job Corrosion	Max Fatigue	Cum. Corrosion	Used String Life
	type	Y/N	Y/N	ft	ft	ft	Name	Y/N	Y/N	%	%		%	%
26/11/2022	Received CT String from Manufacturer			15974		15,974	Zakaria	Y	Y	0	0	0	0	0
20/1/2023	Cut 4ft & spooling into DIDF			15974	4	15,970	Zakaria	N	N	0.33	0.5	0.33	0.5	0.83
23/1/2023	Pump CI and purge with N2		Y	15,970		15,970	Zakaria	Y	Y	0.33	0	0.33	0.5	0.83
23/1/2023	Apply external corrosion inhibitor & cover with canvas	Y		15,970		15,970	Zakaria	Y	Y	0.33	0	0.33	0.5	0.83

Based on above pipe management;

- Current CT Fatigue Life is 0.33 %
- Current String Used Life is 0.83 %
- Current Running Footage in Chrome Completion is 0 ft
- Current Total Running Footage is 0 ft

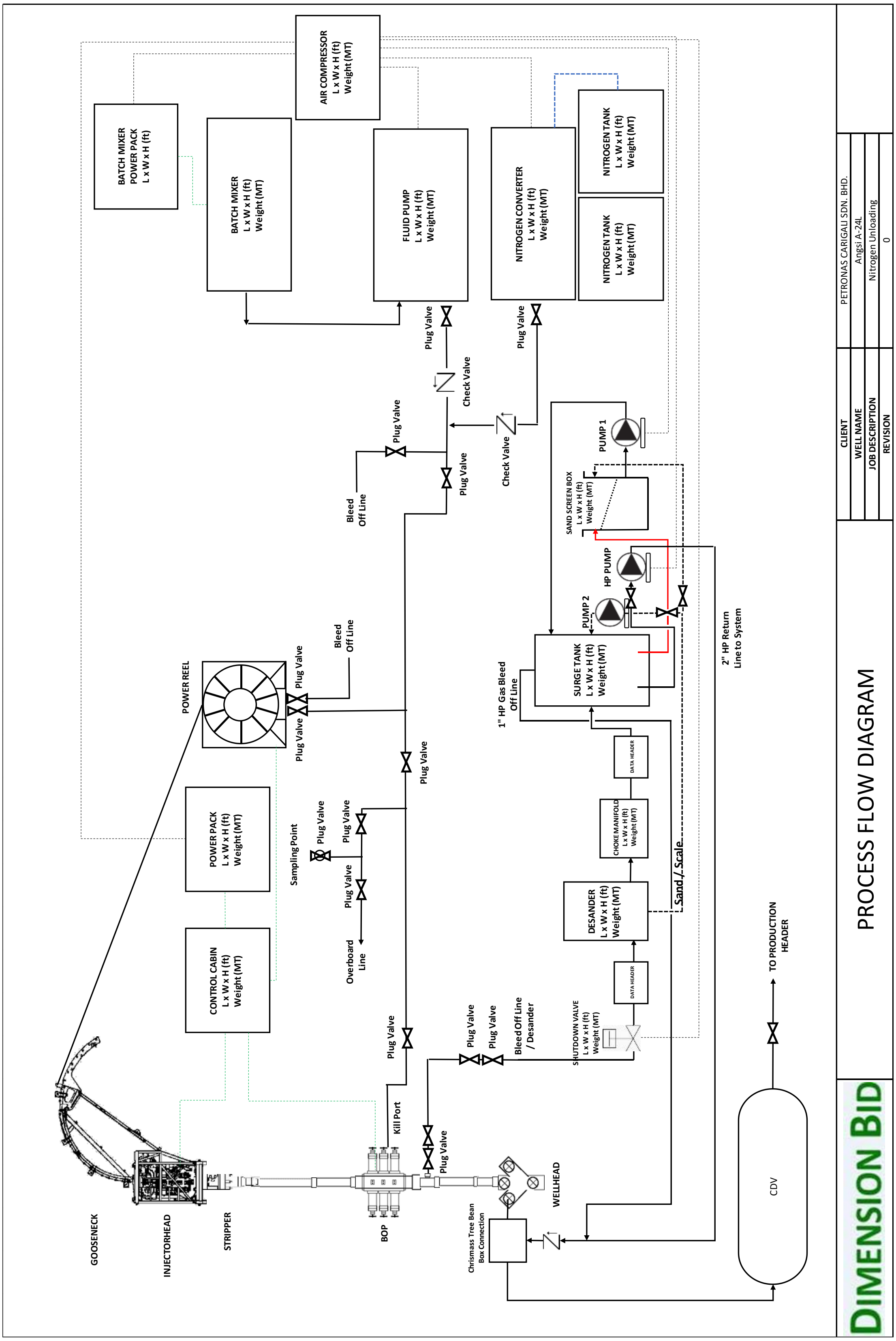
Based on Dimension Bid Standard Operating Procedure (SOP) of Pipe Management for Chrome Completion:

- Max Running Footage in Chrome Completion is **200,000 ft**

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

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

PROCESS FLOW DIAGRAM



SAFETY OPERATIONAL PROCEDURES

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

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

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

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

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

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

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

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

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

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

HEALTH, SAFETY & ENVIRONMENT

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

EQUIPMENT RIG UP PROCEDURE

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

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

    *Observe indicator pin to confirm that all rams are in good working condition.

15. Install the stab-in-guide on the CT then stab the string into injector head.
16. Make up the CT connector and perform pull test at least 15,000 lbs as per DB SOP. This test to be recorded in OrionNet.

    *Do not perform pull test more than 80% from CT Limit. (38,880 lbs)

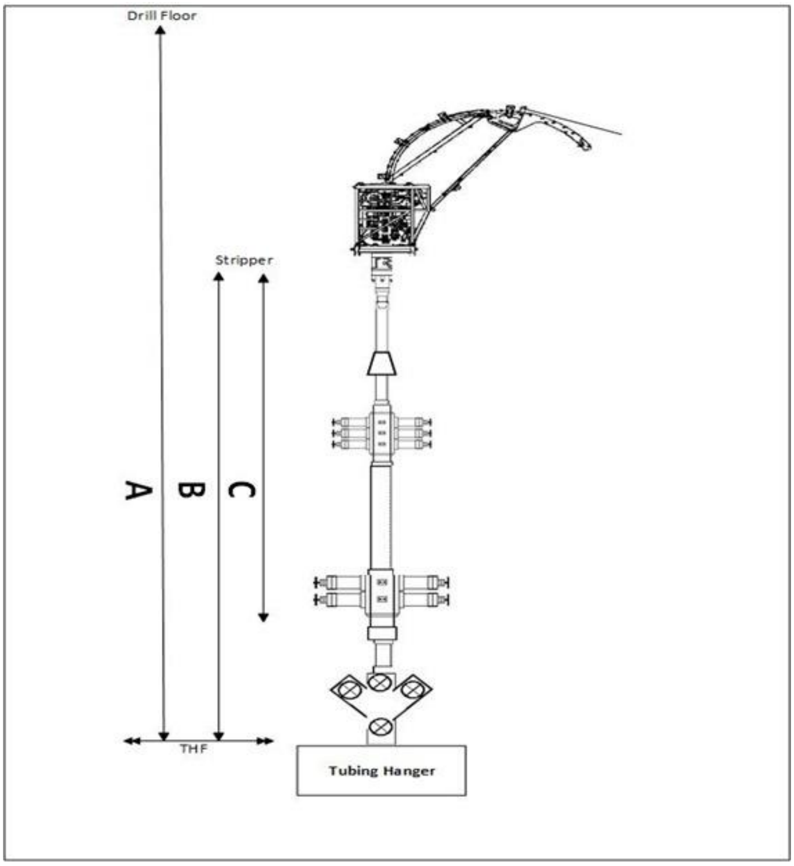
17. Install pressure test plate onto the CT connector.
18. Circulate the string with water until clean return is seen prior to proceed with pressure test CT Connector.
19. Pressure up the CT string to 5000 psi gradually by 500 psi increment then hold for 10 minutes. Pressure test acceptance criteria:
    19.1. For low pressure at 300 psi:

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

19.2. For high pressure at 5000 psi:

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

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



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

*The reference depth is at the tip of BHA

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

EQUIPMENT PRESSURE TESTING PROCEDURE

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

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

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

   5.2. For high pressure at 3000 psi:

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

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

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

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

CT STRING MANAGEMENT DURING OPERATION

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

   This visual inspection needs to be done for every run.
4. As per current Dimension Bid standard, we need to cut the CT 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, lubricate the annulus side of CT string with metal to metal drag reducer solution.
6. After every 1000 ft of running, please ensure to;
   a. Perform pull test
   b. Pump at least 2 bbls of metal to metal drag reducer solution whether through coil or kill port is subject to the tubing head pressure (THP).
7. For additional precaution and by referring to the Angsi A-24L survey deviation below;
   a. Monitor the weight frequently
   b. Perform additional pull test
   c. Pump additional 2 bbls of metal to metal drag reducer solution for every time pull test is conducted or every 1000 ft.

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

.

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

PRE-OPERATIONAL PROCEDURE

SLICKLINE OPERATION

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

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

CT OPERATION (LONG STRING) – RUN #1 NITROGEN UNLOADING

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

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

1. Rig up CTU and surface line on Angsi-A platform as per Site Visit Report:
   - 1.1. Review JHA and risk assessment with all personnel involve in the rig up operation. Please send a copy of JHA to Engineer in Charge.
   - 1.2. Lift up CT unit using crane and spot on platform.
   - 1.3. Rig up CT package and surface treating line.
   - 1.4. Rig up 2" kill line to BOP kill port.
   - 1.5. Rig up 2" flexible hose from pumping tee.
   - 1.6. Ensure pump volume, pump rate, N2 rate, circulating pressure, well head pressure, weight is synchronise with OrionNet DAS.
   - 1.7. Pig CT with treated injection water to ensure no debris is inside CT. **Record CT tubing volume in treatment report.**
   - 1.8. Make up the **CT End Connector**.
   - 1.9. Install the Pull and Pressure Test Sub.
   - 1.10. 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% CT. Consult with town if require.
   - 1.11. Perform Pressure Test on CT End Connector. Pumping treated sea water through the CT, 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.
     - 1.11.1. For low pressure:

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

       Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 4,500 psi) over the 15- minutes test interval after the pressure stabilizes.
2. Make up 2.125" Upward Jetting Nozzle tool as per **BHA#1: 2.125" Upward Jetting Nozzle** in **Appendix I**.
3. Pick up CT and tag the stripper with the BHA.
4. Make up the Injector Head and Stripper to the stack up.
5. CT stack up pressure test against Wellhead Swab valve. Pumping TIW through the CT, 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.
   - 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. Pressure test the BHA Check Valve with **3,000 psi** in the CT stack up, bleed off the stack up pressure to **1,500 psi** via pump-in sub; and bleed off pressure in the CT to zero (0) psi via reel manifold.
   - 6.1. 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.
7. Upon successful test, bleed off the pressure in the CT stack through the pump-in sub.
8. Flush CT string with N2 gas till dry.
9. Zero both depth counters at reference point.
10. Confirm all wellhead and BOP valves are in open position via physical check.
    - 10.1. Prior to opening the wellhead valve pressure up above master valves to a pressure equal to the expected shut-in wellhead pressure.
    - 10.2. Count wellhead valves turns while opening and record it the treatment report for reference in future.
    - 10.3. Manipulate surface valve to the following position:

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

    - 10.4. Record initial SITHP of short string and long string and PCP of well A-24L.
11. Start RIH CT to first circulation point depth at **2,134m / 7,000 ft MDDF** while perform break circulation with 2 bbls of metal to metal drag reducer solution for every 1,000 ft. First circulation point start at 2,134m / 7,000 ft MDDF **/** subject to latest fluid level detected during TCC to clear out fluid column inside tubing until across I-100 Perforation depth at **3,653 m / 11,985 ft MDDF** (maximum circulation depth).
    - 11.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix III.
    - 11.2. Conduct pull test as per for every 300 m / 1,000 ft use CT Fatigue graph as reference. Ensure the CT Fatigue graph is available at location before RIH. Record RIH, Hanging and POOH weight in daily operation report and manual job log at all time.
    - 11.3. Maximum coil speed running in hole is **30-50 ft/min.**
    - 11.4. Slow down coil speed to **10 ft/min**, 50 ft before and after passing through completion accessories.
    - 11.5. Closely observe weight indicator in control cabin while running in hole.
    - 11.6. Observe return all the times. If observed fluid return at surface, station CT at depth to unload all liquid until gas return at surface before proceed to RIH 300 m /1,000 ft deeper.
    - 11.7. Do not exceed operating safety limits **5,000 psi (Circulating Pressure)**
    - 11.8. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
    - 11.9. At all time, while RIH, the injector torque control shall be set at the minimum pressure required to move the CT at specified speed.
    - 11.10. Pump 2 bbls of drag reducer for every 1,000ft interval.
12. At **2,124 m MDDF / 6,969 ft MDDF (10m before first circulation depth)**, stop coil and conduct pull test of 10m/30ft and record the pulling weight both static and dynamic (IMPORTANT).

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

13. Upon completion pull test, continue RIH until **2,134m / 7,000 ft MDDF (first circulation point depth)** and start pumping nitrogen with N2 rate 300 scf/min for 30 minutes while monitoring the returns on surface.

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

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

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

Client PCSB
Well A24L
Field Angsi
Job N2 Unloading
Date 27 March, 2023

DIMENSION BID

No.	Stage	N2 Rate	Total N2	Duration	Coiled Tubing					
		SCFM	SCF	Minute	ft/min	From (ft)	From (m)	To (ft)	To (m)	Total Footage (ft)
1	RIH	300	10500	35	30	0	0	1050	320	1050
2	Pull Test	300	750	3	20	1050	320	1000	305	50
3	RIH	300	10500	35	30	1000	305	2050	625	1050
4	Pull Test	300	750	3	20	2050	625	2000	610	50
5	RIH	300	10500	35	30	2000	610	3050	930	1050
6	Pull Test	300	750	3	20	3050	930	3000	914	50
7	RIH	300	10500	35	30	3000	914	4050	1234	1050
8	Pull Test	300	750	3	20	4050	1234	4000	1219	50
9	RIH	300	10500	35	30	4000	1219	5050	1539	1050
10	Pull Test	300	750	3	20	5050	1539	5000	1524	50
11	RIH	300	10500	35	30	5000	1524	6050	1844	1050
12	Pull Test	300	750	3	20	6050	1844	6000	1829	50
13	RIH	300	10500	35	30	6000	1829	7050	2149	1050
14	Pull Test	300	750	3	20	7050	2149	7000	2133	50
15	**Circulation**	500	15000	30	0	**7000**	2133	**7000**	2133	0
16	RIH	500	17500	35	30	7000	2133	8050	2454	1050
17	Pull test	500	1250	3	20	8050	2454	8000	2438	50
18	**Circulation**	500	15000	30	0	**8000**	2438	**8000**	2438	0
19	RIH	500	17500	35	30	8000	2438	9050	2758	1050
20	Pull test	500	1250	3	20	9050	2758	9000	2743	50
21	**Circulation**	500	15000	30	0	**9000**	2743	**9000**	2743	0
22	RIH	500	17500	35	30	9000	2743	10050	3063	1050
23	Pull test	500	1250	3	20	10050	3063	10000	3048	50
24	**Circulation**	500	15000	30	0	**10000**	3048	**10000**	3048	0
25	RIH	500	17500	35	30	10000	3048	11050	3368	1050
26	Pull test	500	1250	3	20	11050	3368	11000	3353	50
27	**Circulation**	500	15000	30	0	**11000**	3353	**11000**	3353	0
28	RIH	500	16417	33	30	11000	3353	11985	3653	985
29	**Circulation (EOT)**	500	15000	30	0	**11985**	3653	**11985**	3653	0
30	POOH	300	119850	400	30	11985	3653	0	0	11985
		Total N2, SCF	**380,017**	**1,025**	**MINS**					
		Total N2, Gal	**4,081**	**17**	**HOURS**					
		3x Priming	**900**							
		Total N2 Including 3% Losses	**5,130**							

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

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

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

    Note:

    - At 3,653 m MDDF, total fluid column to be displaced is 4 bbls (assuming fluid level is at 3,000 m MDDF).
    - Ensure flowback crew to divert liquid return into surge tank to measure volume displace / recovered at surface.
    - If N2 is found excessive in return, reduce N2 rate and observe return. If no fluid observed at return, try to RIH deeper, adjust N2 rate accordingly, and consult with town before proceed further.

15. 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 a 2 bbl pill at 1.0 bpm through coil.

Friction Reducer Solution (3% Friction Reducer)				**10**	***BBL***	***Description***
Seq.	***Product***	***Concentration***		***Volume***		
1	Injection Water	968	gptg	406	gal	Base Fluid
2	IM Lube	30	gptg	13	gal	Friction Reducer
Mixing Instruction: 1. Prepare injection water in the mixing tank. 2. Add IM Lube into the tank and circulate the mixture at least 10 minutes until homogenous.						

16. Once observe continuous gas return at surface for at least 30 minutes at depth 3,653 m MDDF / 11,985 ft MDDF, POOH CT to surface.

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

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

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

    16.4. Do not exceed CT Operating Limit.

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

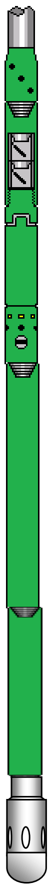
APPENDIX I – BOTTOM HOLE ASSEMBLY SCHEMATIC

BHA #1: 2.125" UPWARD JETTING NOZZLE

DIMENSION BID

BHA DIAGRAM #1 - 2.125" Upward Jetting Nozzle

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

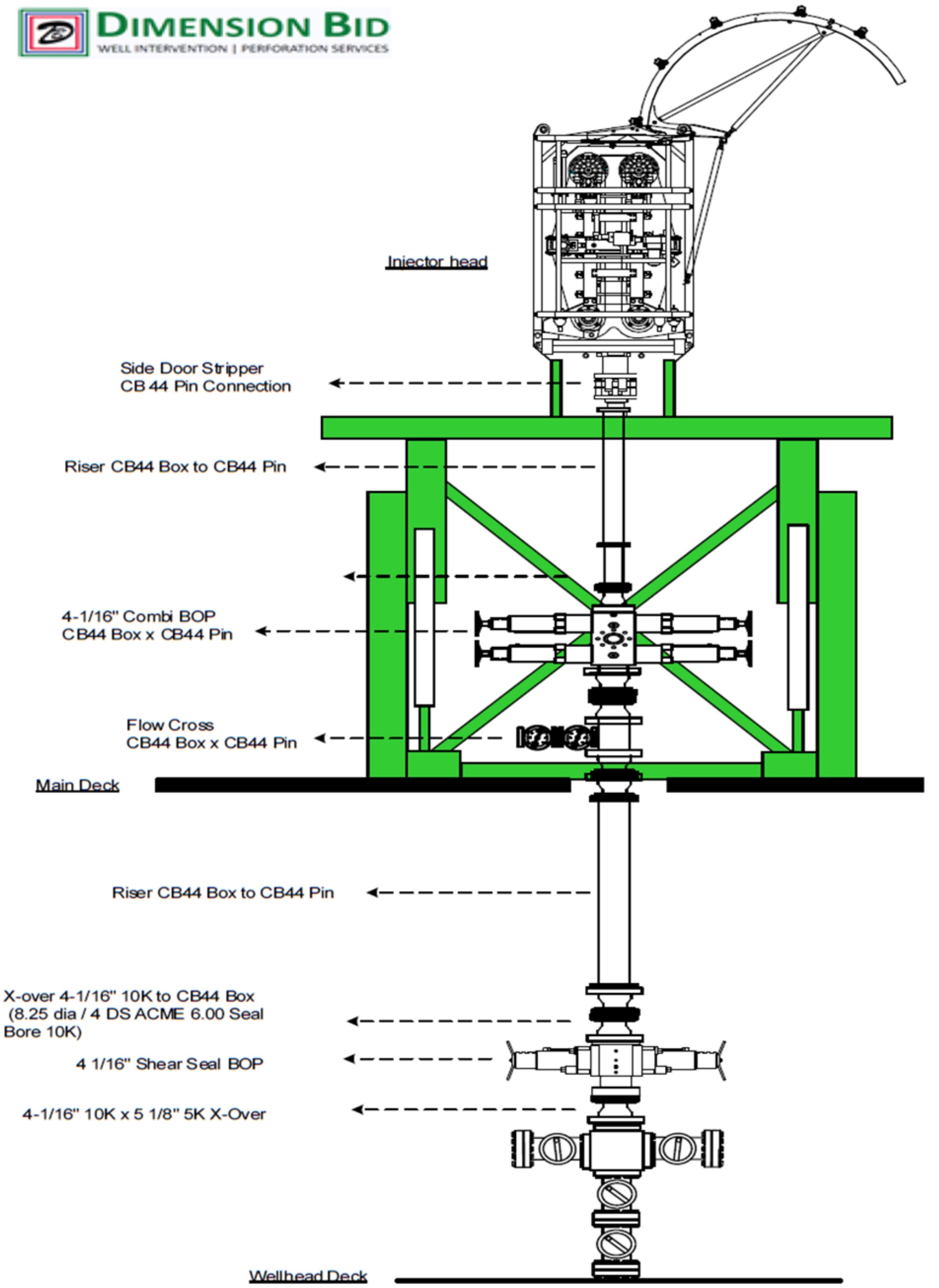
BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	**External Dimple Connector**	1.5" CT	1.5" AMMT PIN		2.125	0.6	0.6
	MHA Disconnect drop ball 3/4" Shear pressure 5,636 psi Circulating drop ball 5/8" Shear pressure 2,520 psi Burst Disc 5000 psi	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	2.125
MINIMUM ID	

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

ADDITIONAL INFORMATION:

APPENDIX II – COILED TUBING STACK UP



APPENDIX III – ENGINEERING ANALYSIS

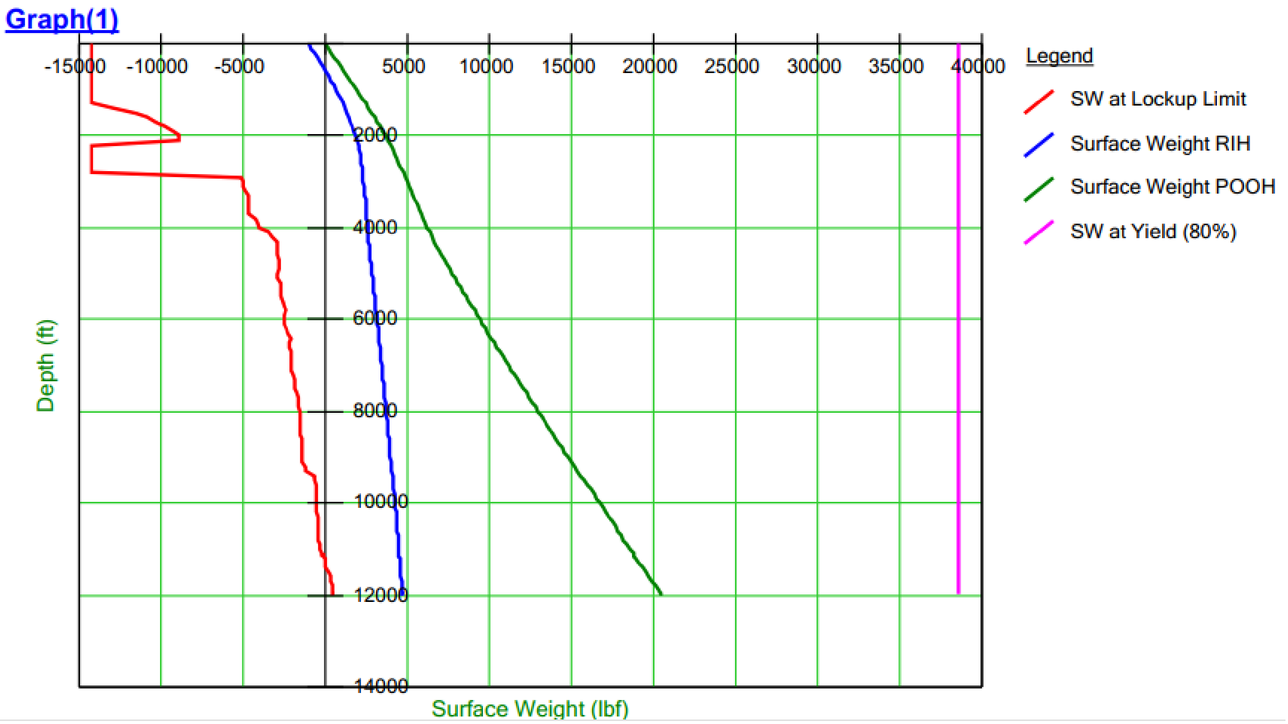
Summary Tubing Force Analysis

- Calculation at depth 3,653 m MDDF / 11,985 ft MDDF

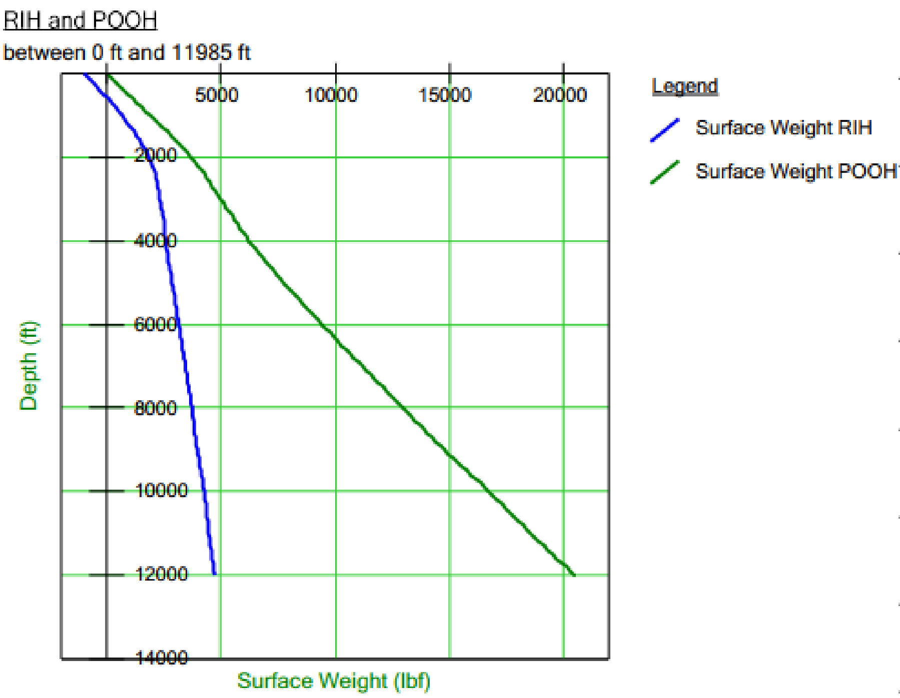
Parameter	Maximum set down weight (lbf)	Surface weight reading (lbf)	Maximum pick up weight (lbf)	Surface weight reading (lbf)
Upward Nozzle with 300 scf/min	-2576	512	10708	38552

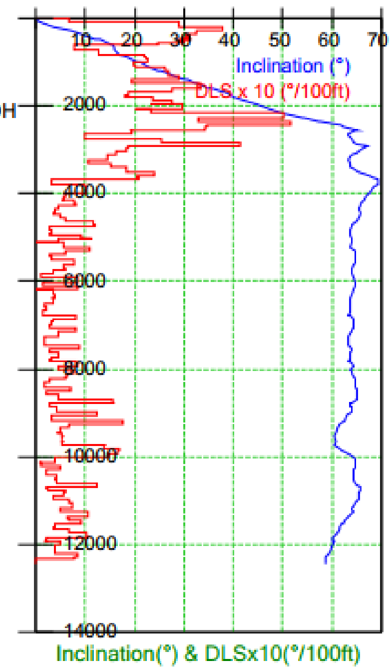
TUBING FORCE ANALYSIS (Orpheus Modelling)

- Run #1 (Upward Jetting Nozzle) with **300 scf/min**



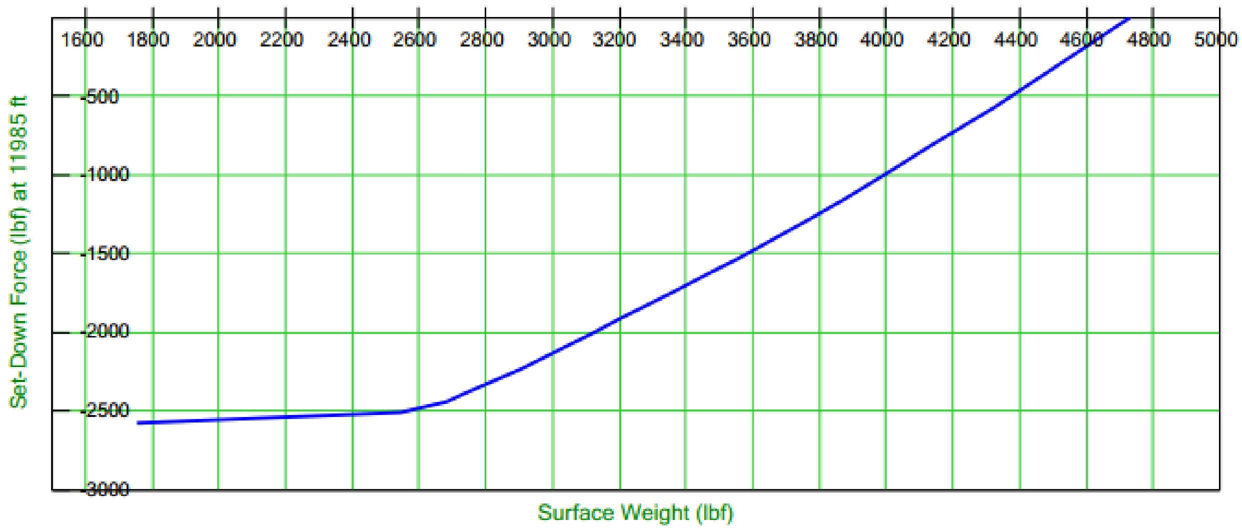
RIH & POOH WEIGHT





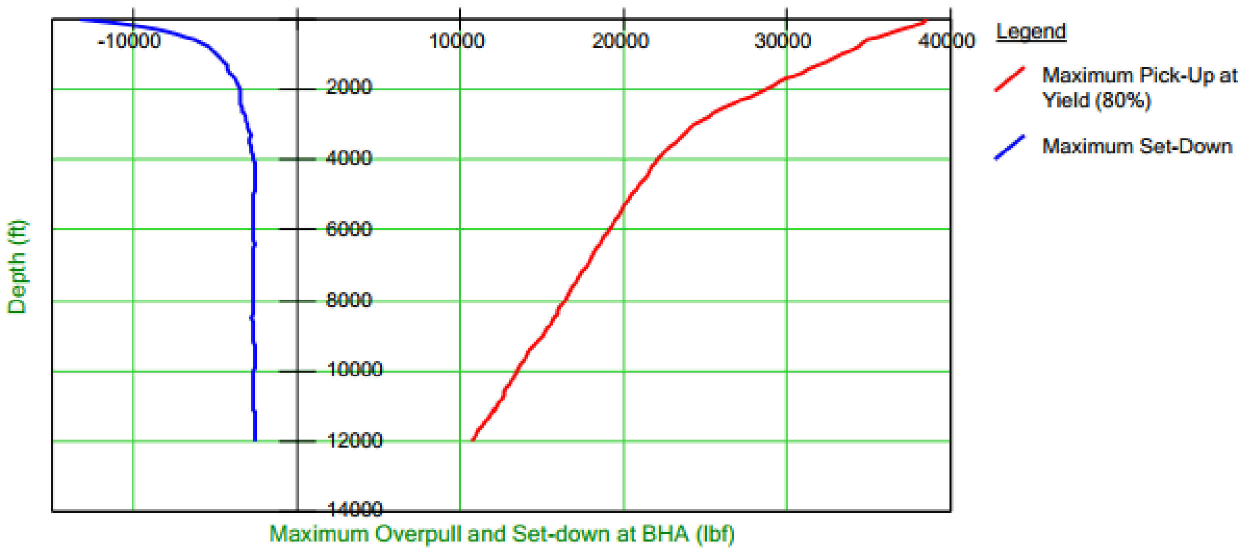
MAXIMUM STRING SET DOWN LIMIT

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



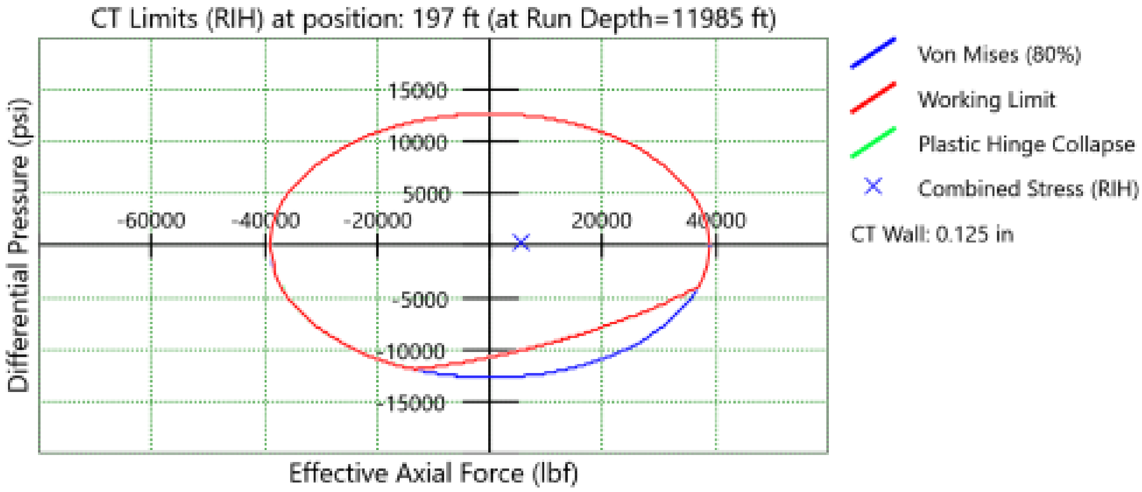
MAXIMUM STRING PICK UP LIMIT

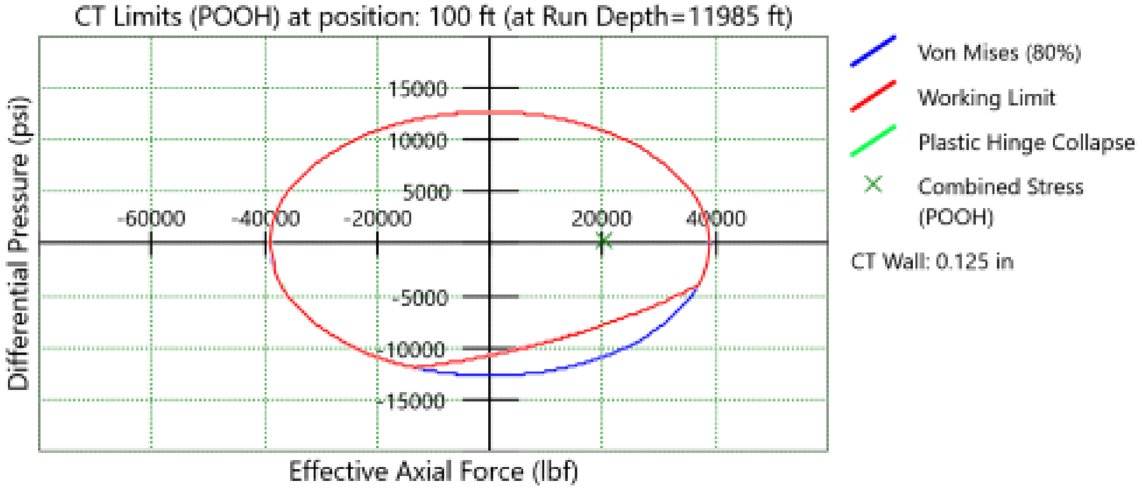
MD1 The available pick-up at 11985 ft based on 80% of yield strength is 10708 lbf.
The weight indicator reading will then be 38552 lbf.



STRING LIMIT

CT Limits





APPENDIX IV – EMERGENCY PROCEDURE

EMERGENCY BOP OPERATIONS

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

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

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

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

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

Actuating the BOP System Hydraulic Controls

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

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

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

LEAK IN COILED TUBING AT SURFACE

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

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

LEAK IN COILED TUBING BELOW SURFACE

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

Note:

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

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

LEAK IN SURFACE PRESSURE CONTROL EQUIPMENT

Stuffing Box

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

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

Surface Leaks Other Than Stuffing Box

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

Note: Avoid collapse situation

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

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

Rotating Joint Leak

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

COILED TUBING RUNS AWAY INTO WELL

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

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

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

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

COILED TUBING IS PULLED OUT OF STUFFING BOX

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

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

COILED TUBING COLLAPSED AT SURFACE

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

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

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

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

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

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

COILED TUBING BREAKS AT SURFACE

If Coiled Tubing breaks at surface into two separate sections:

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

BUCKLED TUBING

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

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

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

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

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

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

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

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

1. Stop the pumps and pick up slowly.

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

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

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

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

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

COILED TUBING STUCK IN HOLE PROCEDURES

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

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

Other factors to be considered are:

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

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

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

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

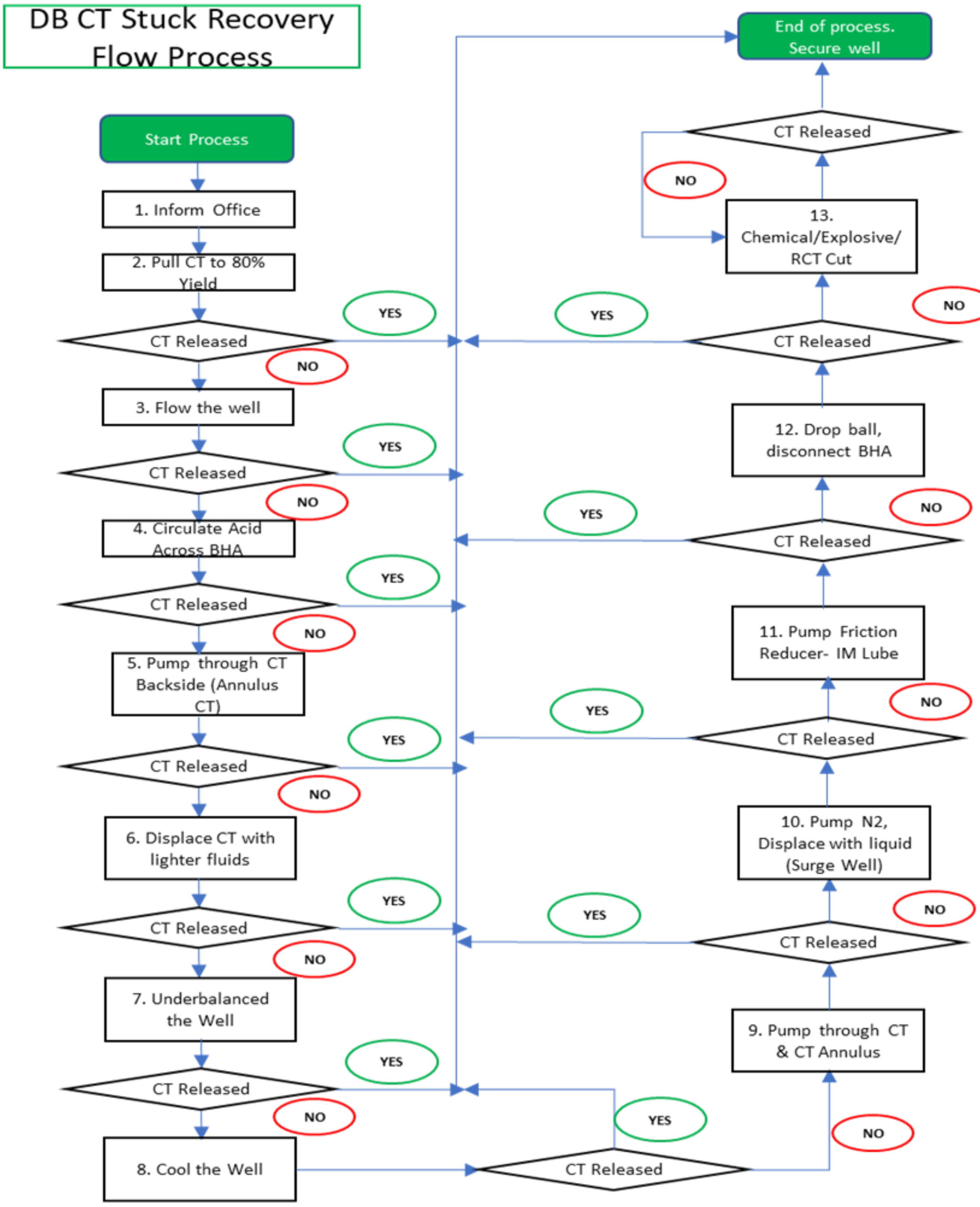
The following are options that may be appropriate depending on the particular circumstances:

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

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

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

STUCK CT COIL RECOVERY PROCESS



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

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

APPENDIX V – PROJECT OPERATION TIMELINE

Dimension Bid Sdn Bhd

DIMENSION BID

Project Lead: Muhd Ameerul Zaeem
Project Start Date: 10/4/2023
Display Week: 1

Week 1 4 / 10 / 23 | Week 2 4 / 17 / 23

Month	Job Description	Well No	Field	Start	End	Cal. Days
	Angsi A CTU Operation Timeline					
May	Skid out from Well A12S	A24L	Angsi A	10/4/2023	10/4/2023	1
May	Rig up on well & well preparation	A24L	Angsi A	11/4/2023	11/4/2023	1
May	CTU Run#1: Nitrogen Unloading	A24L	Angsi A	12/4/2023	13/4/2023	2
May	Monitor well flowing	A24L	Angsi A	14/4/2023	15/4/2023	2
May	Contingency CTU: Nitrogen Unloading	A24L	Angsi A	16/4/2023	17/4/2023	2
May	Skid to well A-38	A24L	Angsi A	18/4/2023	19/4/2023	2
					Total Days:	**10**