Island Drilling

13th Norwegian Plug & Abandonment seminar

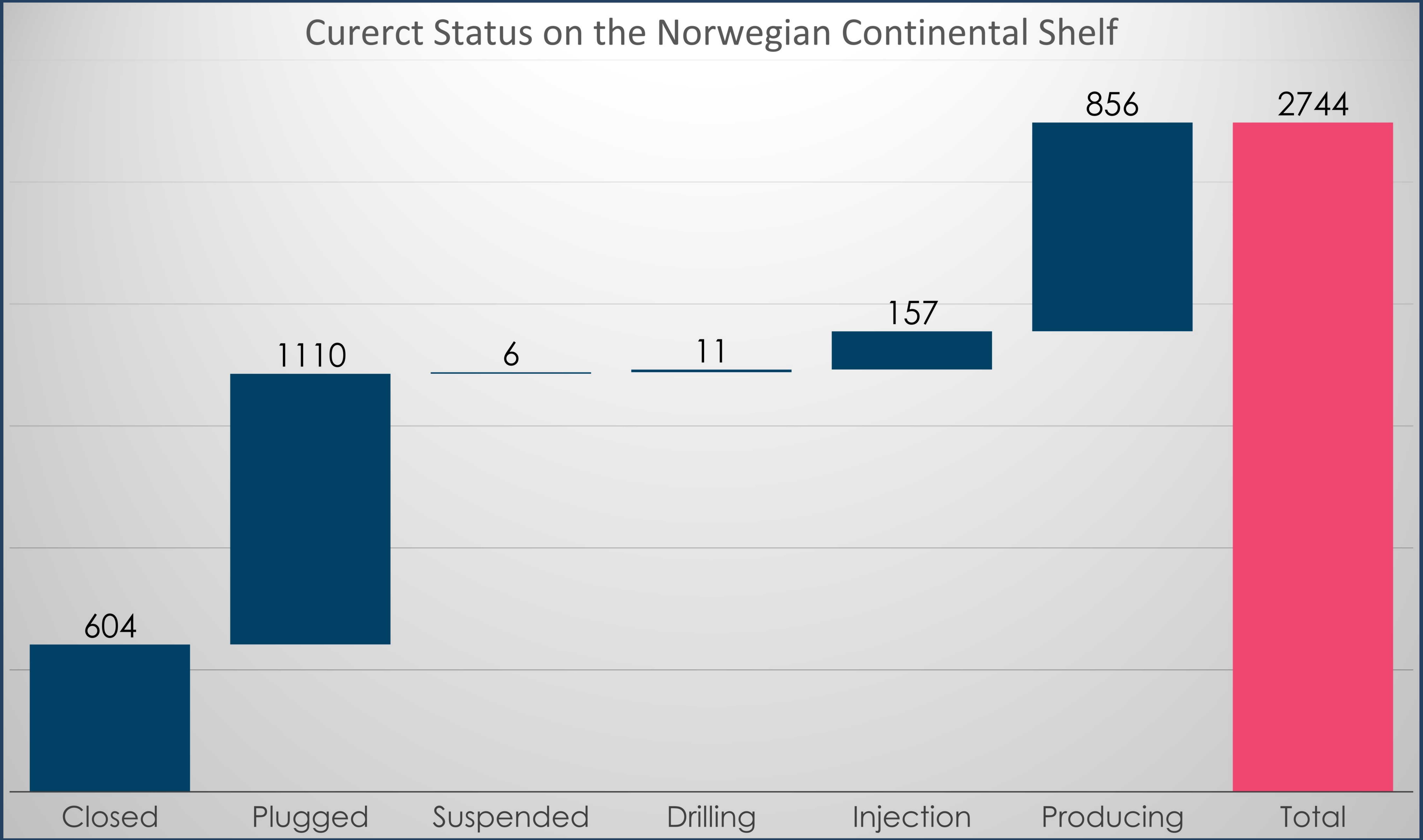
ISLAND DRILLING

Norway

- Offshore Norge estimated in 2013 3000 wells to plug
  - *35 days average/15 rigs working in 20 year*
- Based on the ongoing activity at that time – additional 2880 wells to be drilled during the 20-year period.
  - *35 days average / 15 rigs working in 40 years*
  - *Estimated NOK 876 bn / NOK 429*
- In 2014 the cost was estimated to NOK 360 bn

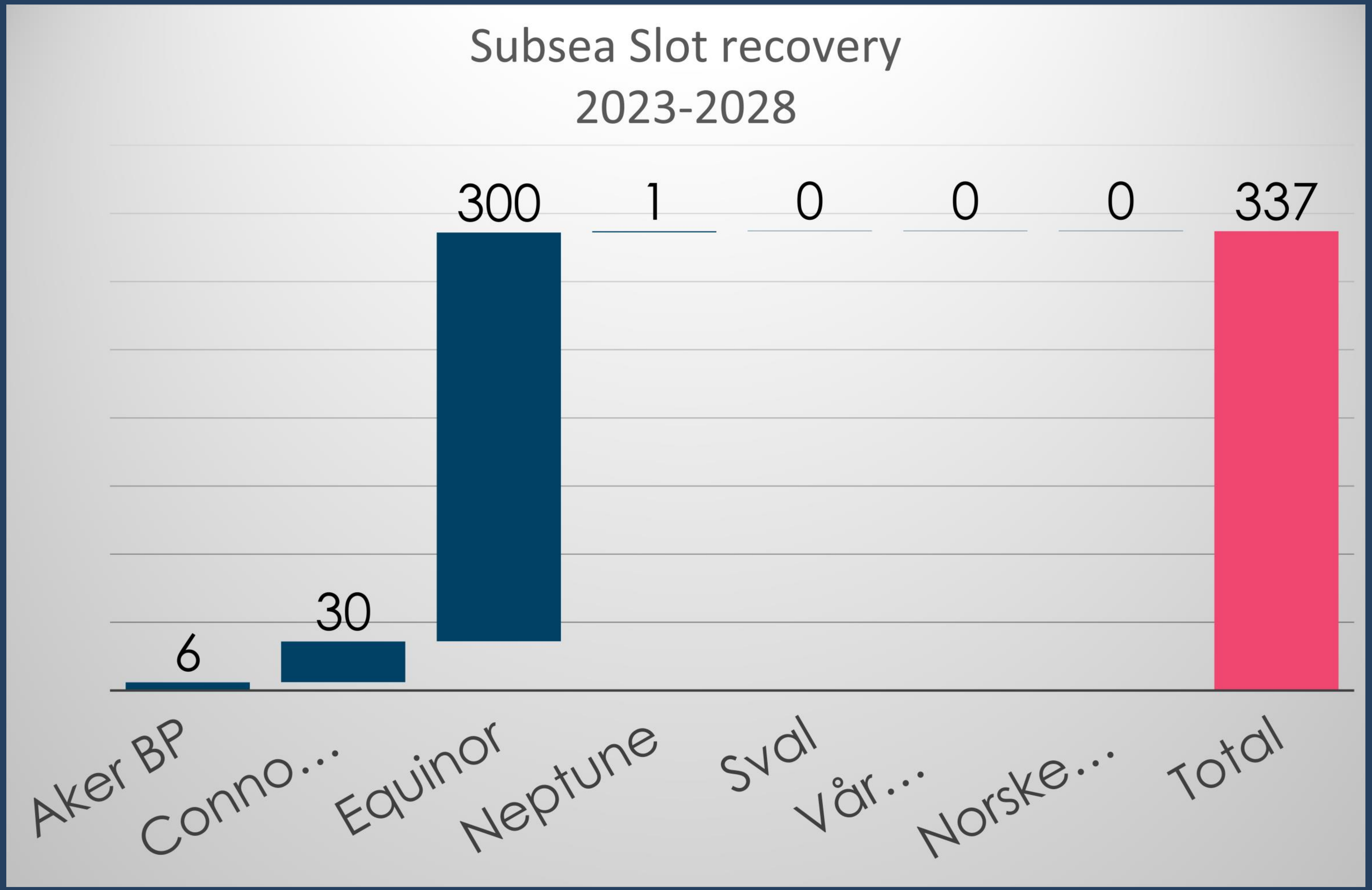
UK

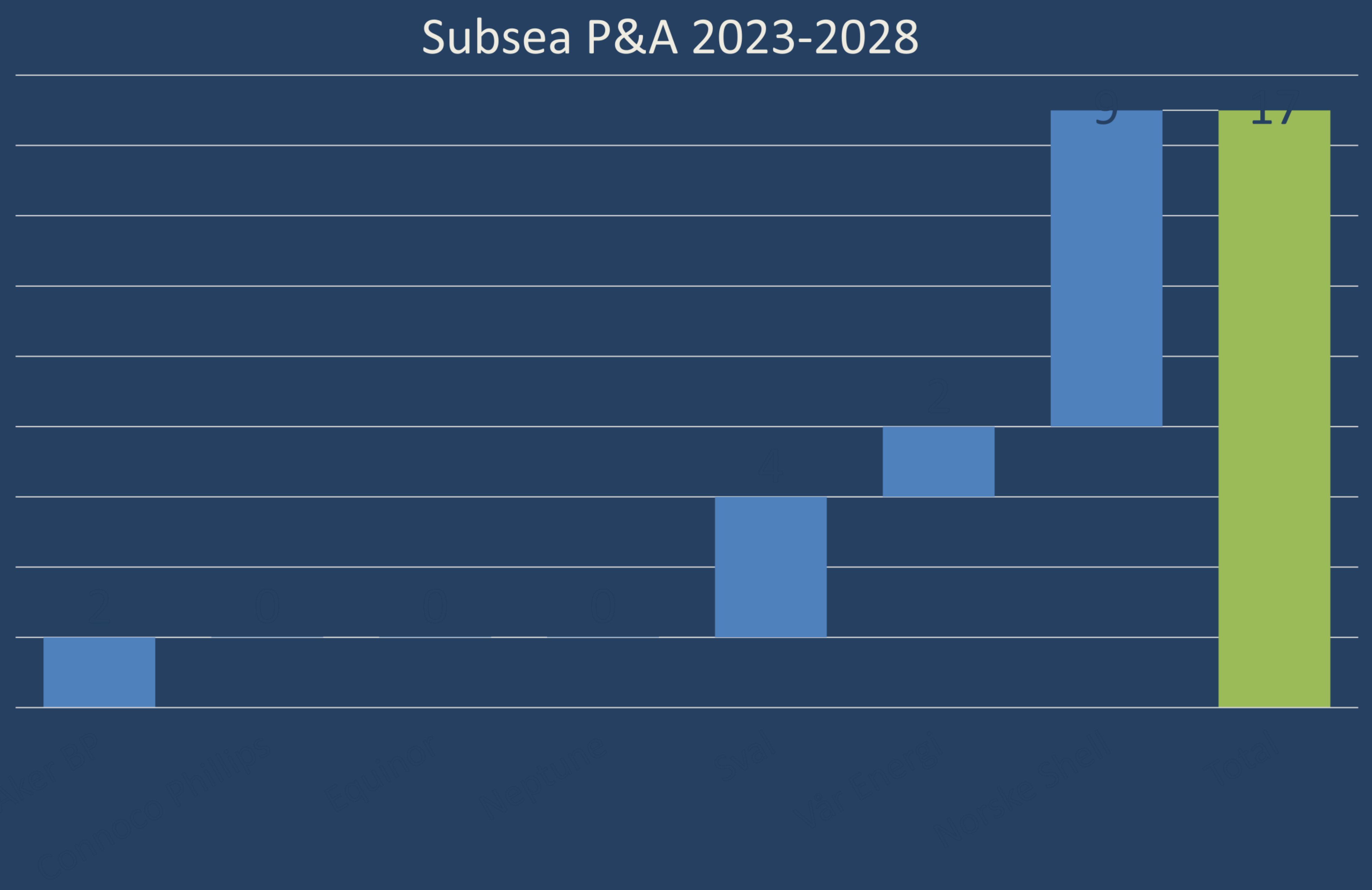
- North Sea decommissioning is currently estimated to cost £10bn between 2023 and 2032.
  - *940 inactive wells*
  - *500 slipped behind deadline*
  - *Currently an average of 120 wells decommissioned each year*



Source: https://factpages.sodir.no/nb-no/wellbore/TableView/Development

Estimated subsea Slot recovery & P&A, 2023-2028

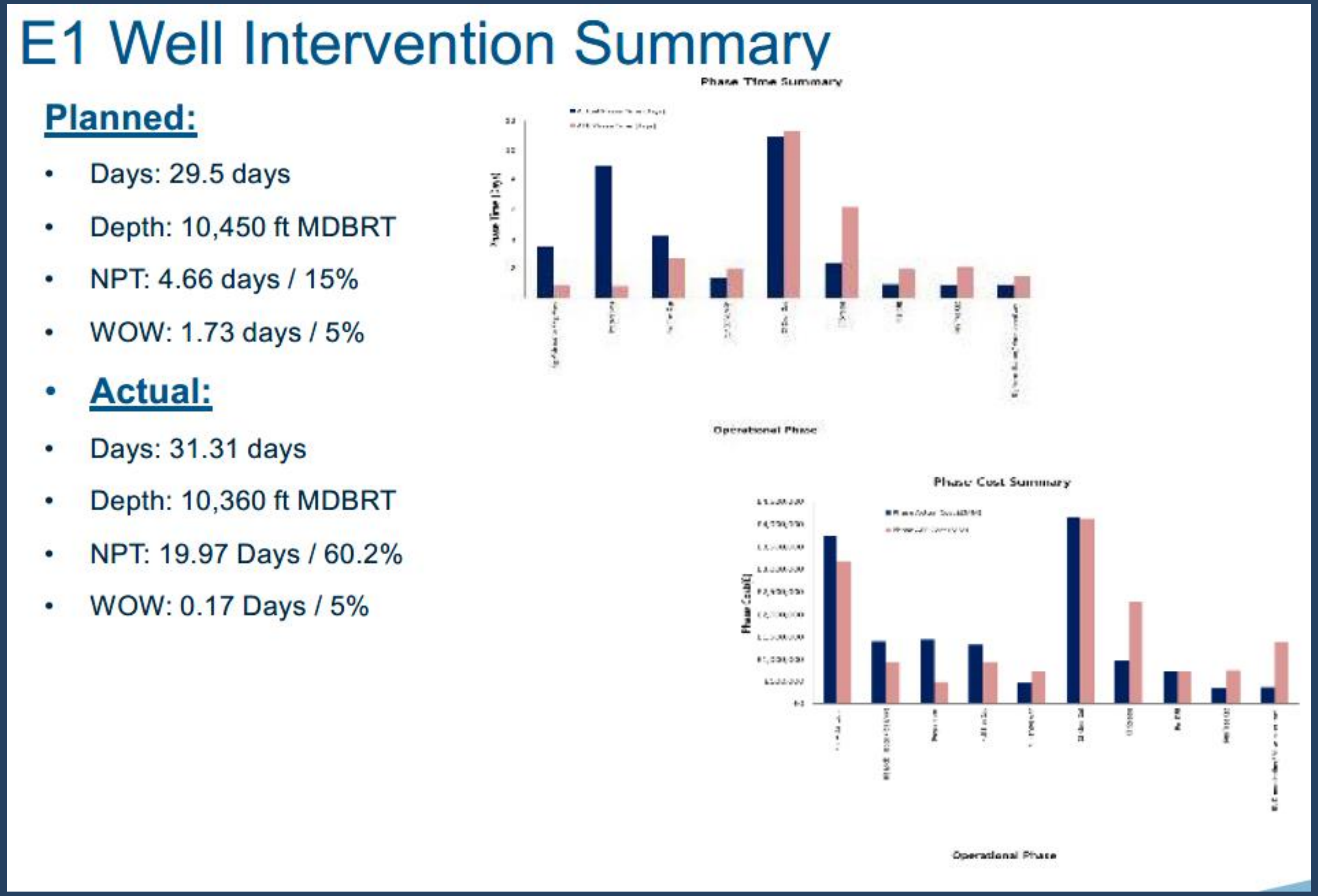


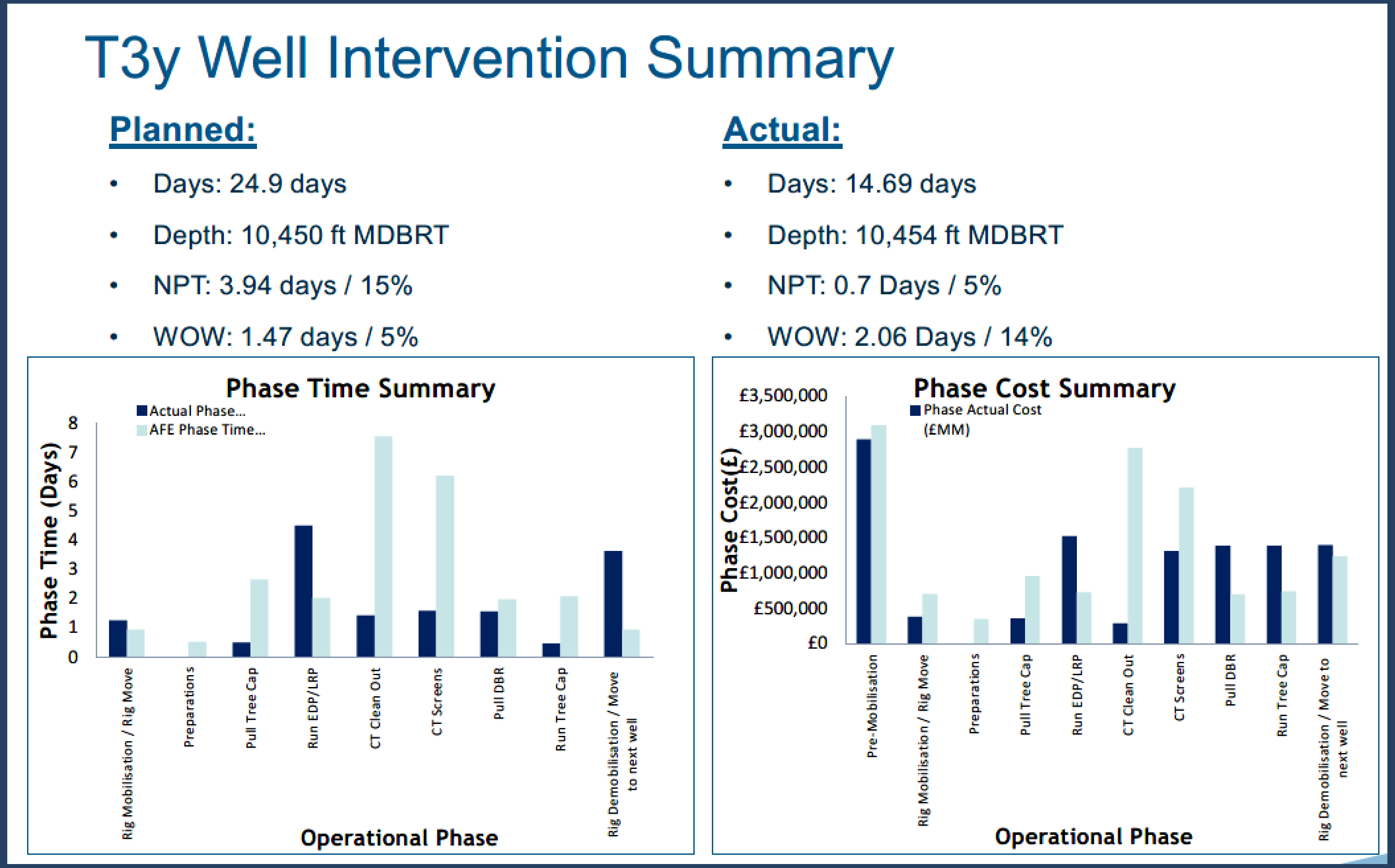


Source: Offshore Norge (24.01.2024)

Our Track Record

Slot recovery – UKSC and EG



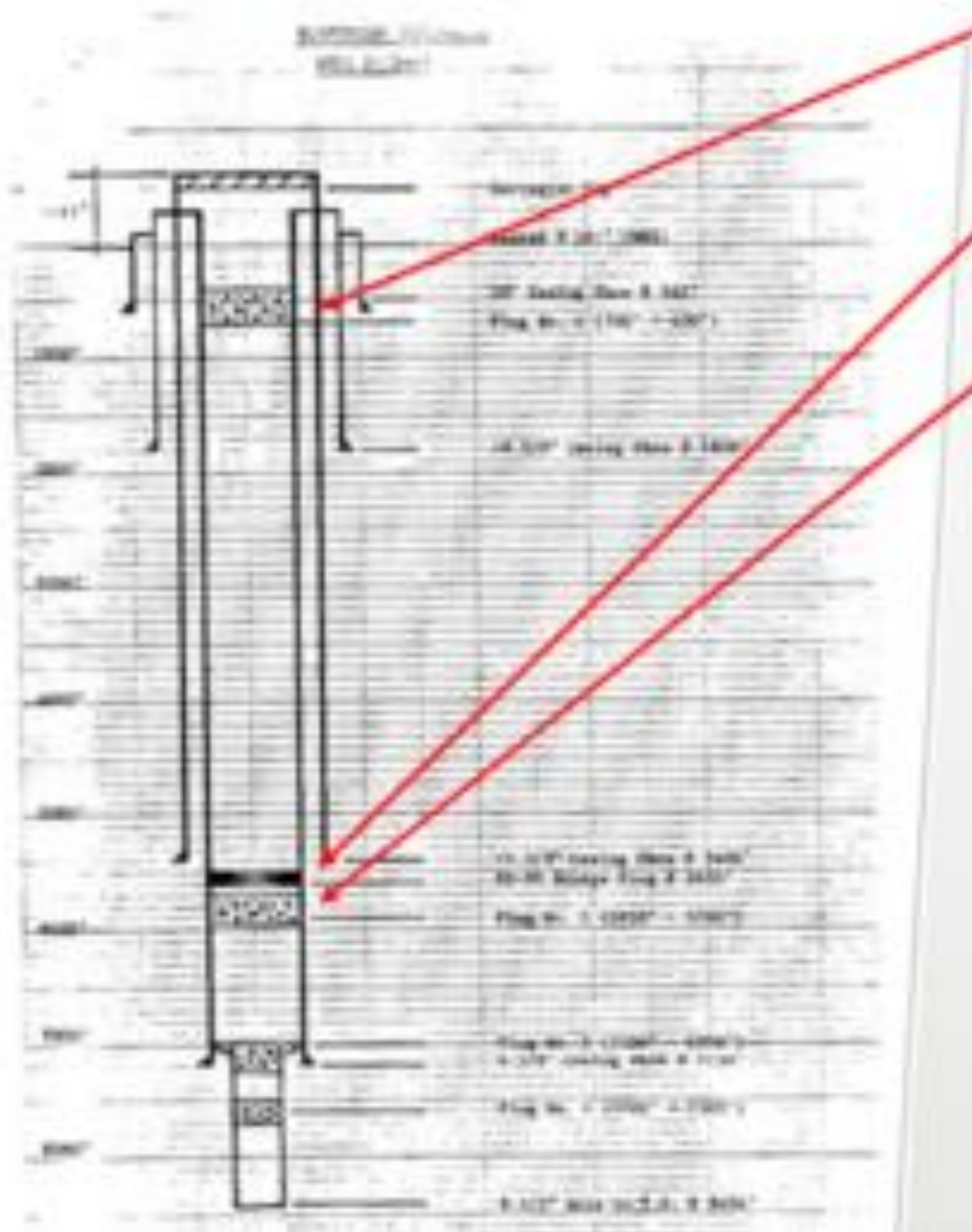


Contry	Well	Planned (days)	Actual (days)
EG	C-38	16	38
	C-21	18	6**

Our Track Record

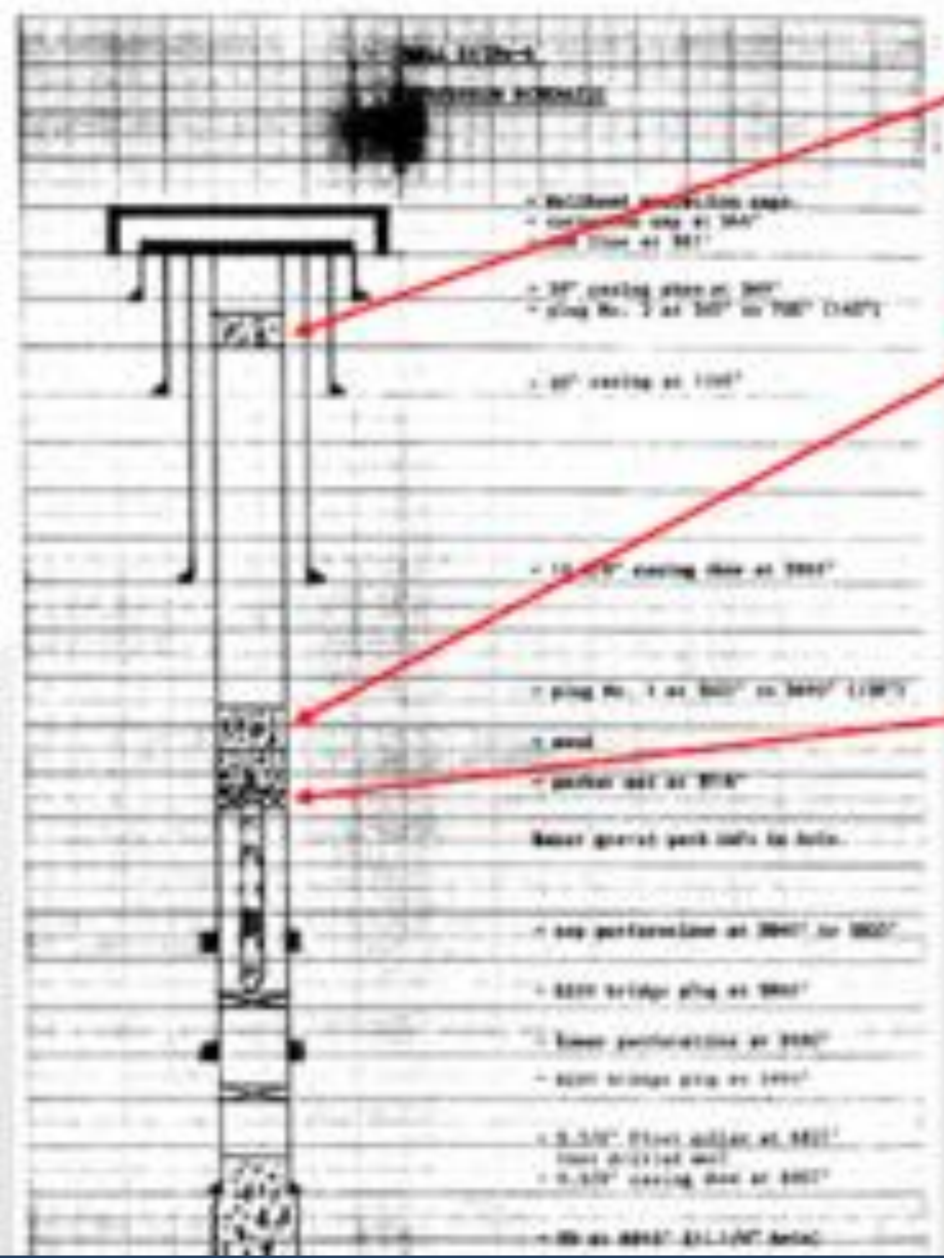
Plug and abandonment - UKSC

21/24-2, Drilled 1984 Eocene tested



- +/- 300 ft Shallow cement plug. Tagged at 421 ft and tested to 1,000 psi
- EZ-SV at 5,666 ft tagged with 15k and tested to 2,000 psi
- Reservoir abandonment plug – planned at 250 ft.
- 9 ⅝" cement logged. +/- 336 ft of good to moderate cement present above reservoir. TOC inside previous shoe, questionable quality
- Openhole isolation plug set over the 9 ⅝" casing shoe Tagged with 15k and tested to 16.0 ppg EMW

21/29a-6 Drilled 1984, Eocene tested

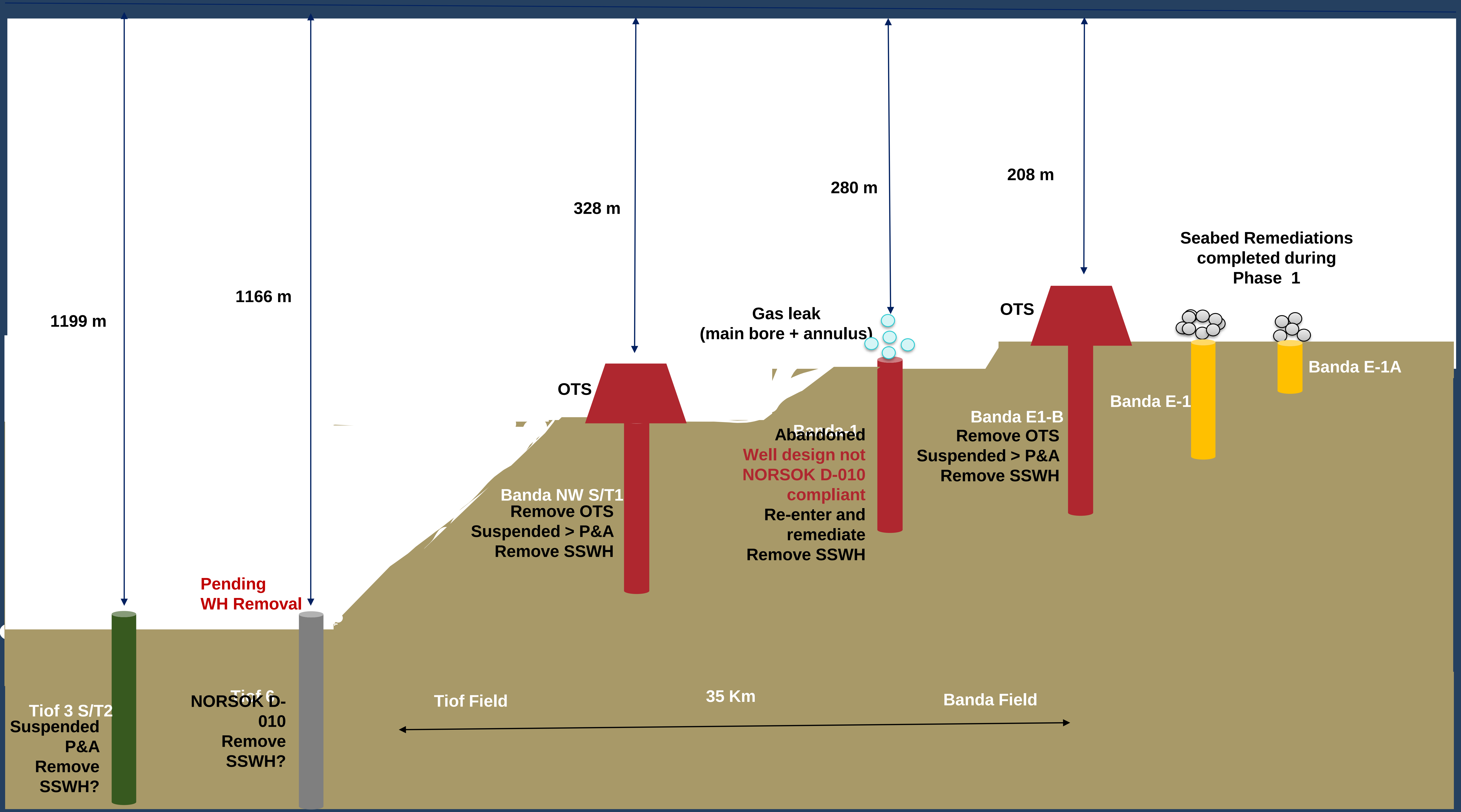


- +/- 140 ft Shallow cement plug. Tagged at 560 ft and tested to 1,000 psi
- Reservoir abandonment plug – 172 ft. Set on a sand plug and packer. Tagged at 5,519 ft with 90 klb
- Gravel pack packer set at 5,732 ft, verification not recorded.
- 9 ⅝" cement logged. +/- 1,020 ft of good to moderate cement present above reservoir. TOC inside previous shoe, questionable quality

- Both wellheads judged to have insufficient fatigue life left
  - BOP will be tethered which will require installation of 4 a gravity bases and associated eqpt using the rig crane
  - Bollards already present on the BOP frame (tethering last done 2022)

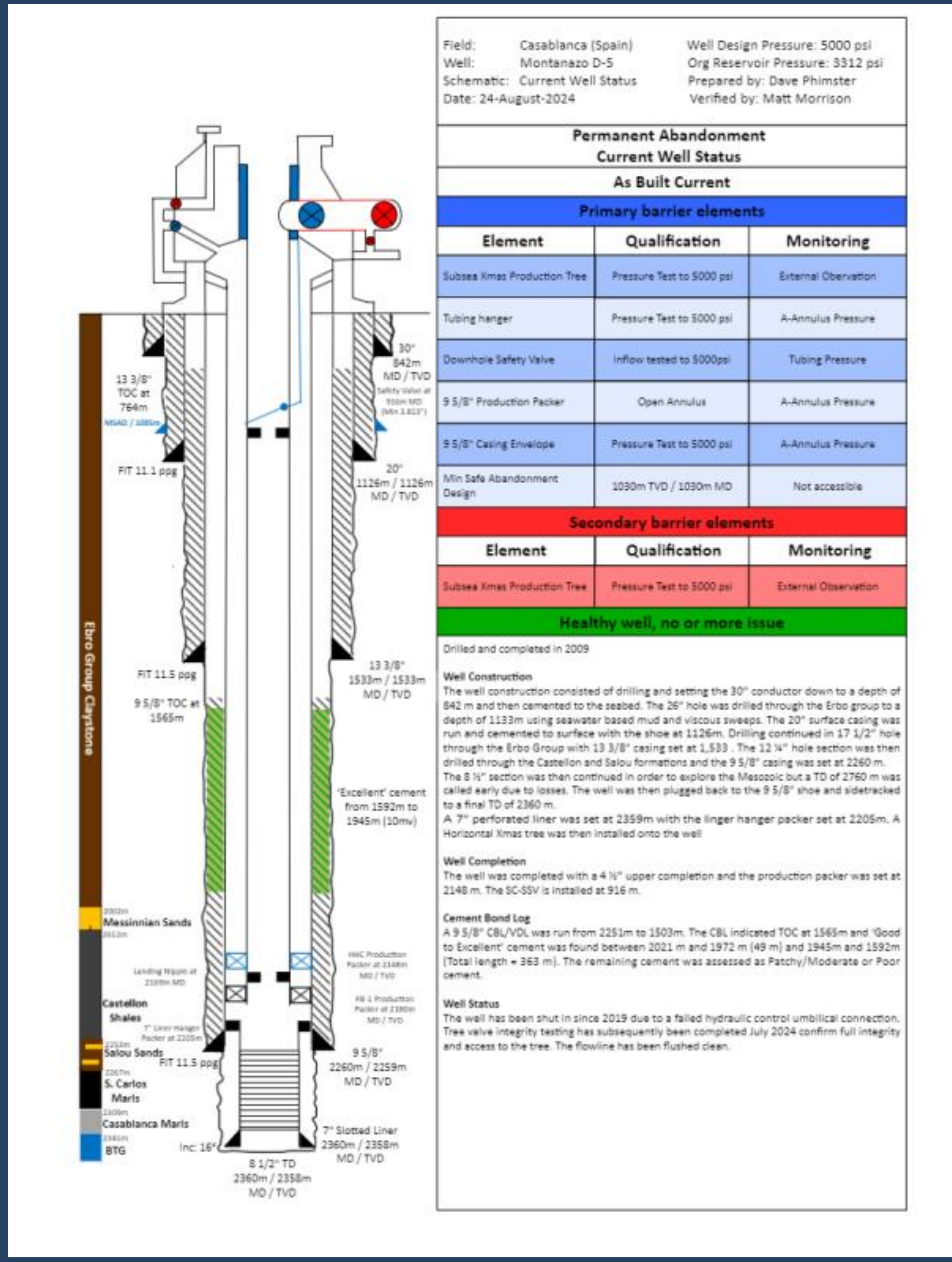
Our Track Record

Plug and abandonment - Mauritania



Our Track Record - Planned

Plug and abandonment - Spain



Field: Casablanca (Spain)
Well: Montanazo D-5
Schematic: Current Well Status
Date: 24-August-2024

Well Design Pressure: 5000 psi
Org Reservoir Pressure: 3312 psi
Prepared by: Dave Phimster
Verified by: Matt Morrison

Permanent Abandonment
Current Well Status
As Built Current

Primary barrier elements		
Element	**Qualification**	**Monitoring**
Subsea Xmas Production Tree	Pressure Test to 5000 psi	External Obervation
Tubing hanger	Pressure Test to 5000 psi	A-Annulus Pressure
Downhole Safety Valve	Inflow tested to 5000psi	Tubing Pressure
9 5/8" Production Packer	Open Annulus	A-Annulus Pressure
9 5/8" Casing Envelope	Pressure Test to 5000 psi	A-Annulus Pressure
Min Safe Abandonment Design	1030m TVD / 1030m MD	Not accessible
Secondary barrier elements		
Element	**Qualification**	**Monitoring**
Subsea Xmas Production Tree	Pressure Test to 5000 psi	External Observation
Healthy well, no or more issue		

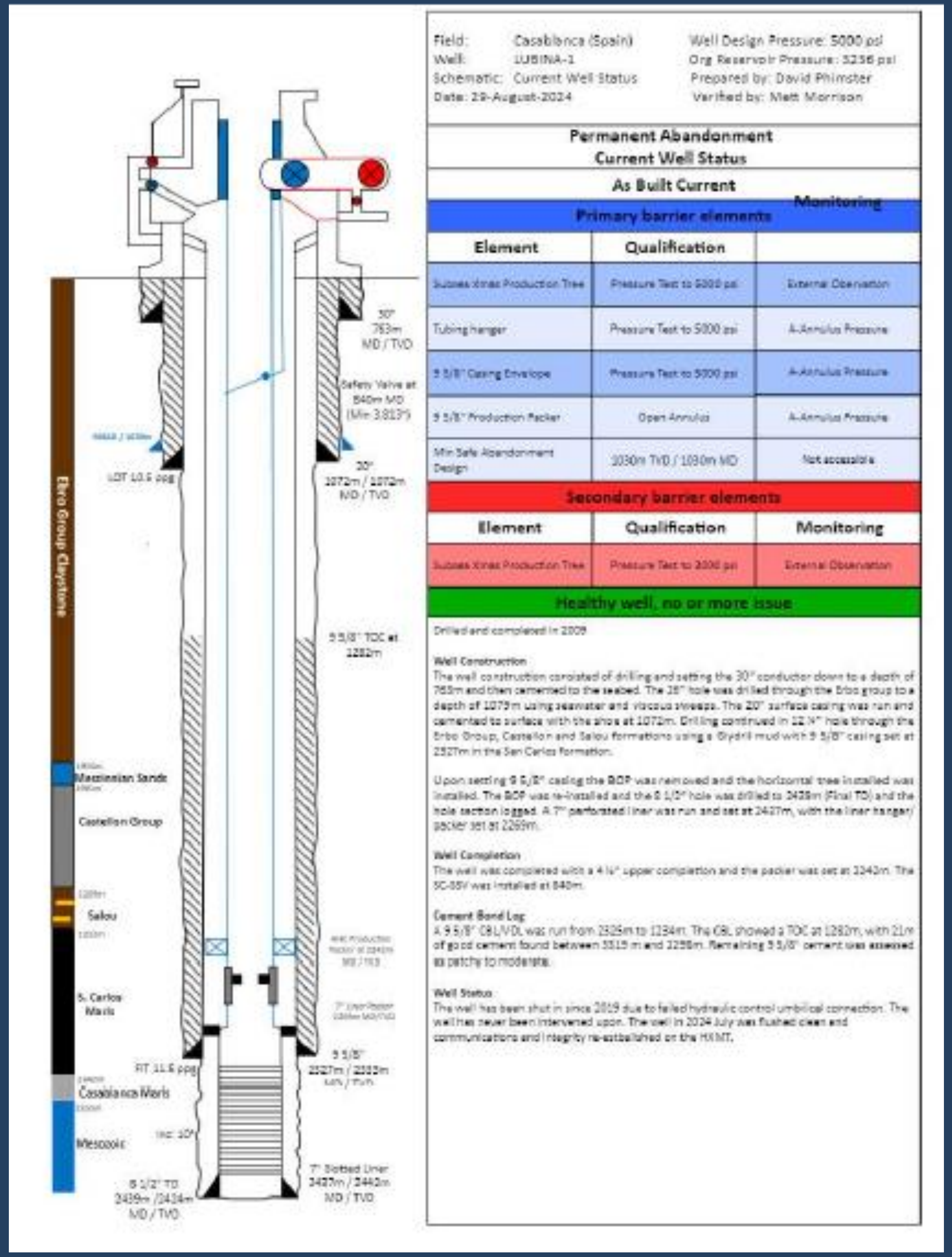
Drilled and completed in 2009

Well Construction
The well construction consisted of drilling and setting the 30" conductor down to a depth of 842 m and then cemented to the seabed. The 26" hole was drilled through the Erbo group to a depth of 1133m using seawater based mud and viscous sweeps. The 20" surface casing was run and cemented to surface with the shoe at 1126m. Drilling continued in 17 1/2" hole through the Erbo Group with 13 3/8" casing set at 1,533 . The 12 ¼" hole section was then drilled through the Castellon and Salou formations and the 9 5/8" casing was set at 2260 m.
The 8 ½" section was then continued in order to explore the Mesozoic but a TD of 2760 m was called early due to losses. The well was then plugged back to the 9 5/8" shoe and sidetracked to a final TD of 2360 m.
A 7" perforated liner was set at 2359m with the linger hanger packer set at 2205m. A Horizontal Xmas tree was then installed onto the well

Well Completion
The well was completed with a 4 ½" upper completion and the production packer was set at 2148 m. The SC-SSV is installed at 916 m.

Cement Bond Log
A 9 5/8" CBL/VDL was run from 2251m to 1503m. The CBL indicated TOC at 1565m and 'Good to Excellent' cement was found between 2021 m and 1972 m (49 m) and 1945m and 1592m (Total length = 363 m). The remaining cement was assessed as Patchy/Moderate or Poor cement.

Well Status
The well has been shut in since 2019 due to a failed hydraulic control umbilical connection. Tree valve integrity testing has subsequently been completed July 2024 confirm full integrity and access to the tree. The flowline has been flushed clean.



Field: Casablanca (Spain)
Well: LUBINA-1
Schematic: Current Well Status
Date: 29-August-2024

Well Design Pressure: 5000 psi
Org Reservoir Pressure: 3256 psi
Prepared by: David Phimster
Verified by: Matt Morrison

Permanent Abandonment
Current Well Status
As Built Current

Primary barrier elements		Monitoring
Element	**Qualification**	
Subsea Xmas Production Tree	Pressure Test to 5000 psi	External Obervation
Tubing hanger	Pressure Test to 5000 psi	A-Annulus Pressure
9 5/8" Casing Envelope	Pressure Test to 5000 psi	A-Annulus Pressure
9 5/8" Production Packer	Open Annulus	A-Annulus Pressure
Min Safe Abandonment Design	1030m TVD / 1030m MD	Not accessible
Secondary barrier elements		
Element	**Qualification**	**Monitoring**
Subsea Xmas Production Tree	Pressure Test to 2000 psi	External Observation
Healthy well, no or more issue		

Drilled and completed in 2009

Well Construction
The well construction consisted of drilling and setting the 30" conductor down to a depth of 763m and then cemented to the seabed. The 26" hole was drilled through the Erbo group to a depth of 1079m using seawater and viscous sweeps. The 20" surface casing was run and cemented to surface with the shoe at 1072m. Drilling continued in 12 ¼" hole through the Erbo Group, Castellon and Salou formations using a Glydril mud with 9 5/8" casing set at 2527m in the San Carlos formation.

Upon setting 9 5/8" casing the BOP was removed and the horizontal tree installed was installed. The BOP was re-installed and the 8 1/2" hole was drilled to 2439m (Final TD) and the hole section logged. A 7" perforated liner was run and set at 2437m, with the liner hanger/ packer set at 2269m.

Well Completion
The well was completed with a 4 ½" upper completion and the packer was set at 2242m. The SC-SSV was installed at 840m.

Cement Bond Log
A 9 5/8" CBL/VDL was run from 2325m to 1234m. The CBL showed a TOC at 1282m, with 21m of good cement found between 2315 m and 2258m. Remaining 9 5/8" cement was assessed as patchy to moderate.

Well Status
The well has been shut in since 2019 due to failed hydraulic control umbilical connection. The well has never been intervened upon. The well in 2024 July was flushed clean and communications and integrity re-estbalished on the HXMT.

Our experiences

- Wellhead fatigue
  - *Old well judged to have insufficient fatigue life left*
  - *Require BOP tethering*
- Interface between Xmas Tree and BOP Wellhead Connector
  - *Require modification or change out of WH connector*
  - *Wellhead type with DX Connector*
- Unable to perform full BOP test according to API 53 5th edition.
  - *Age of assets installed are pre-dating API 53 STD.*
- Cement
  - *Cement is a material which can crack and create leakages*
  - *Lack of cement behind casing*
- Equipment
  - *A lot of equipment is required (Pending the planned operation)*
- Extensive mobilization phase
  - *Prior to UKSC – 10 days at shipyard*
  - *Prior to EG operations – 16 days outside Luba*
  - *Prior to Spain operation – 10 days planned at Las Palmas*
- High POB
  - *Average BOP during P&A and Slot recovery was 115*
  - *Average POB during planned POB will be approx. 115-118*
- Huge cost

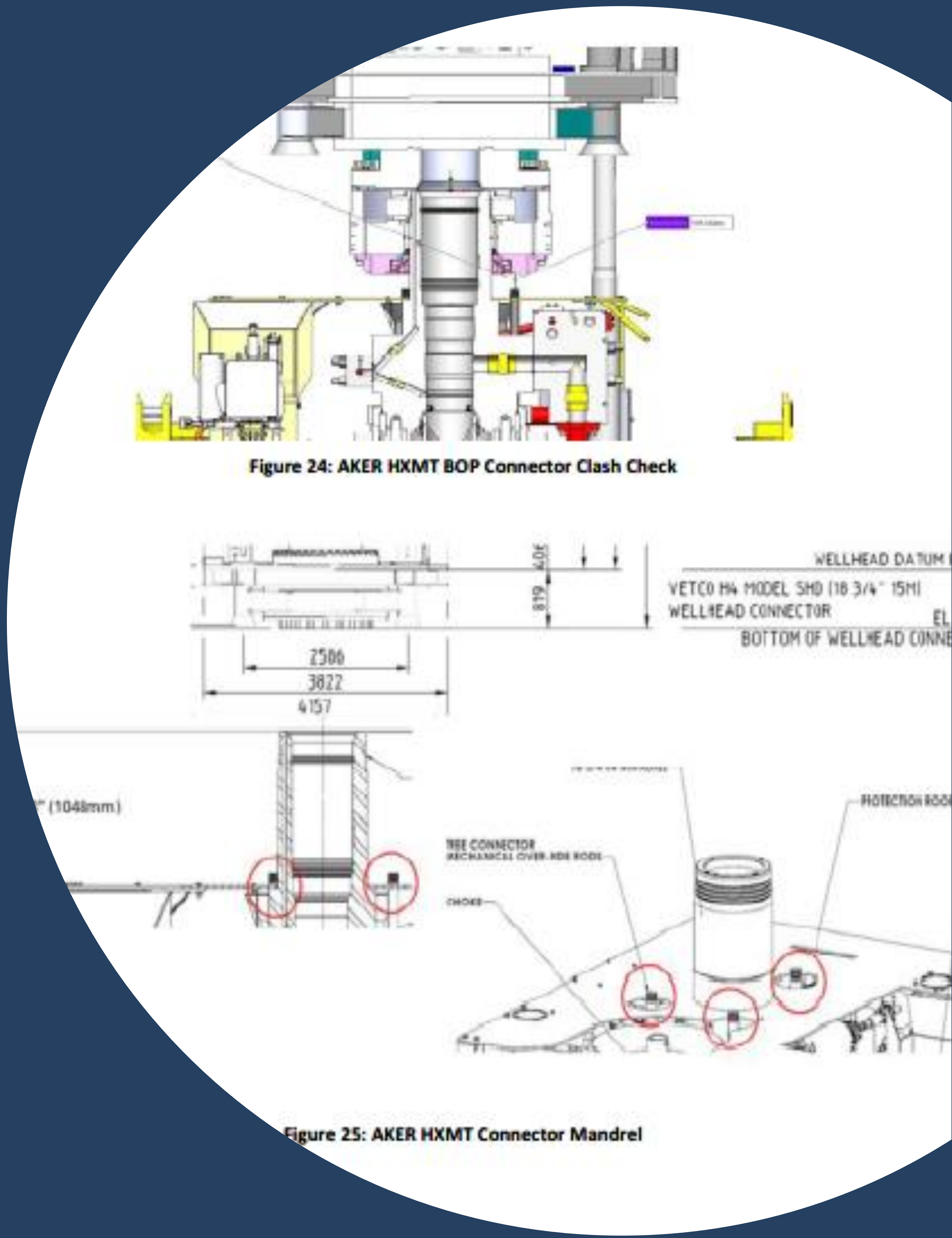
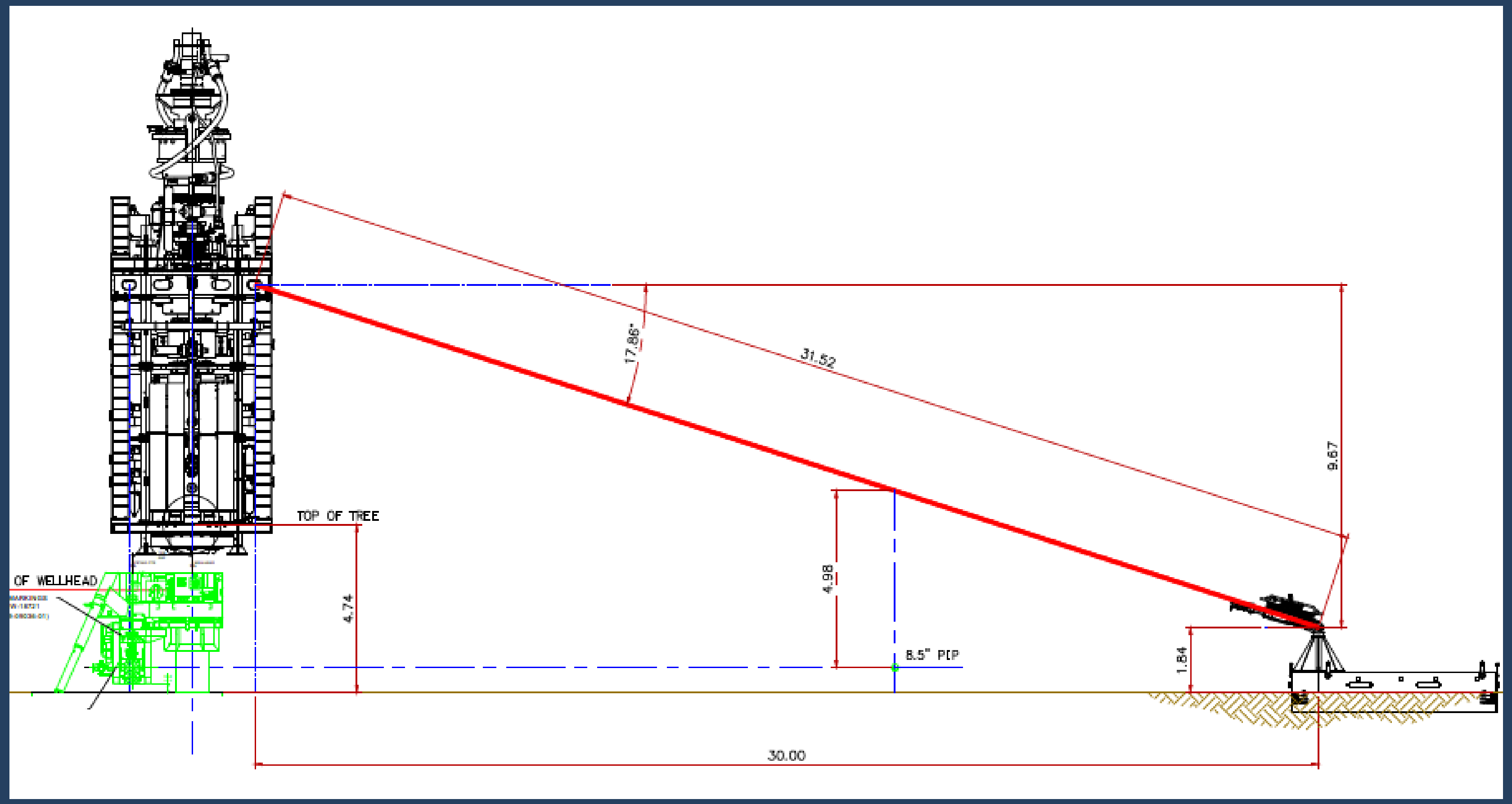


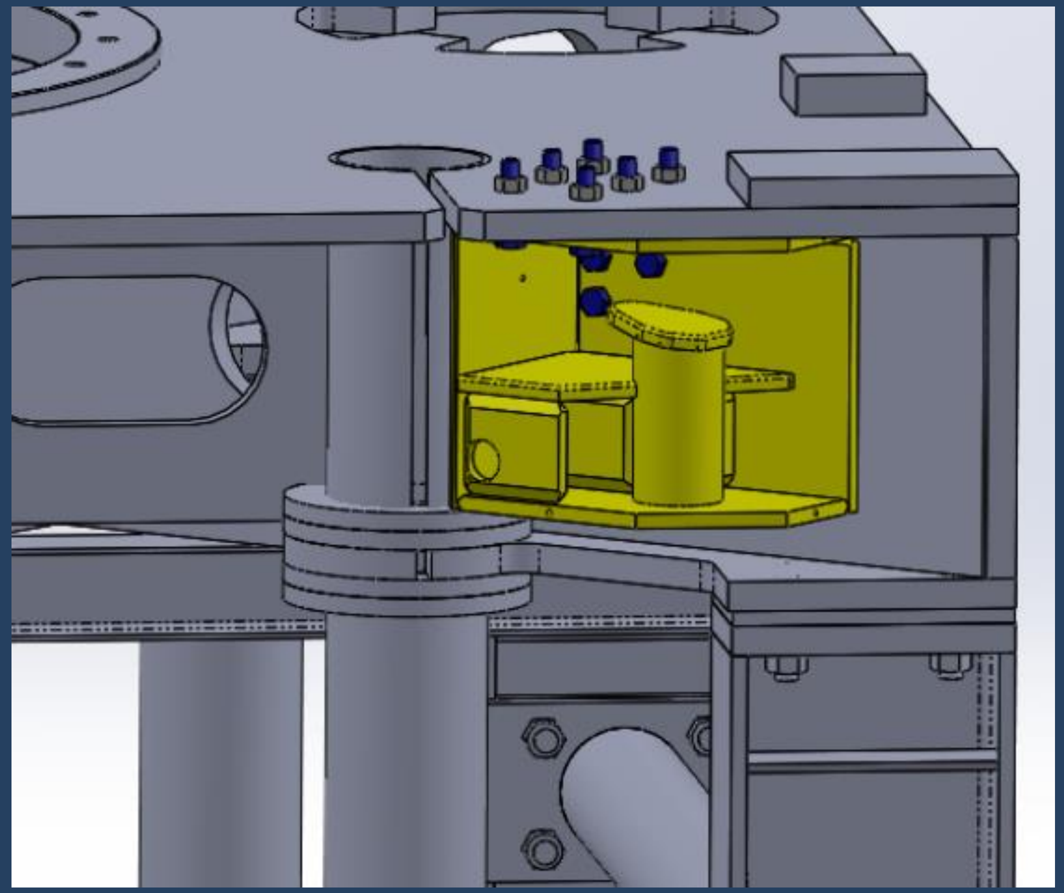
Figure 24: AKER HXMT BOP Connector Clash Check

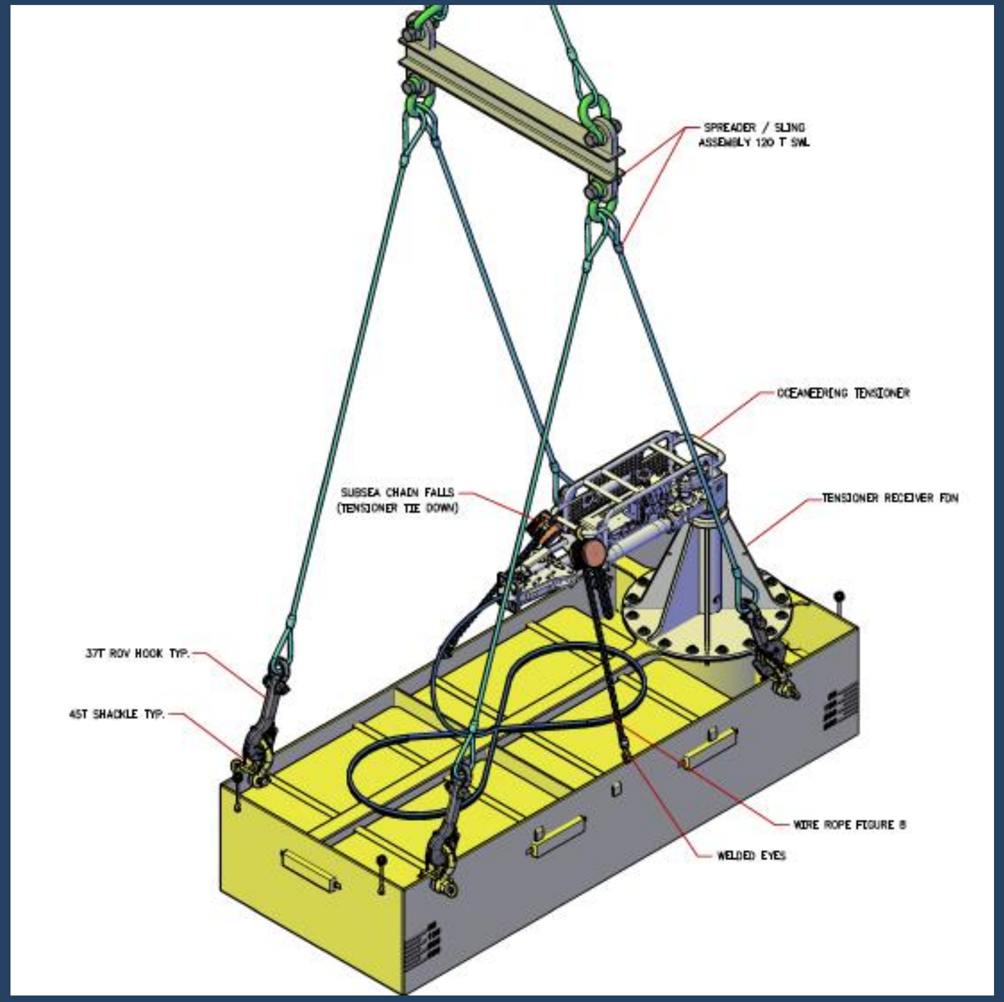
Figure 25: AKER HXMT Connector Mandrel

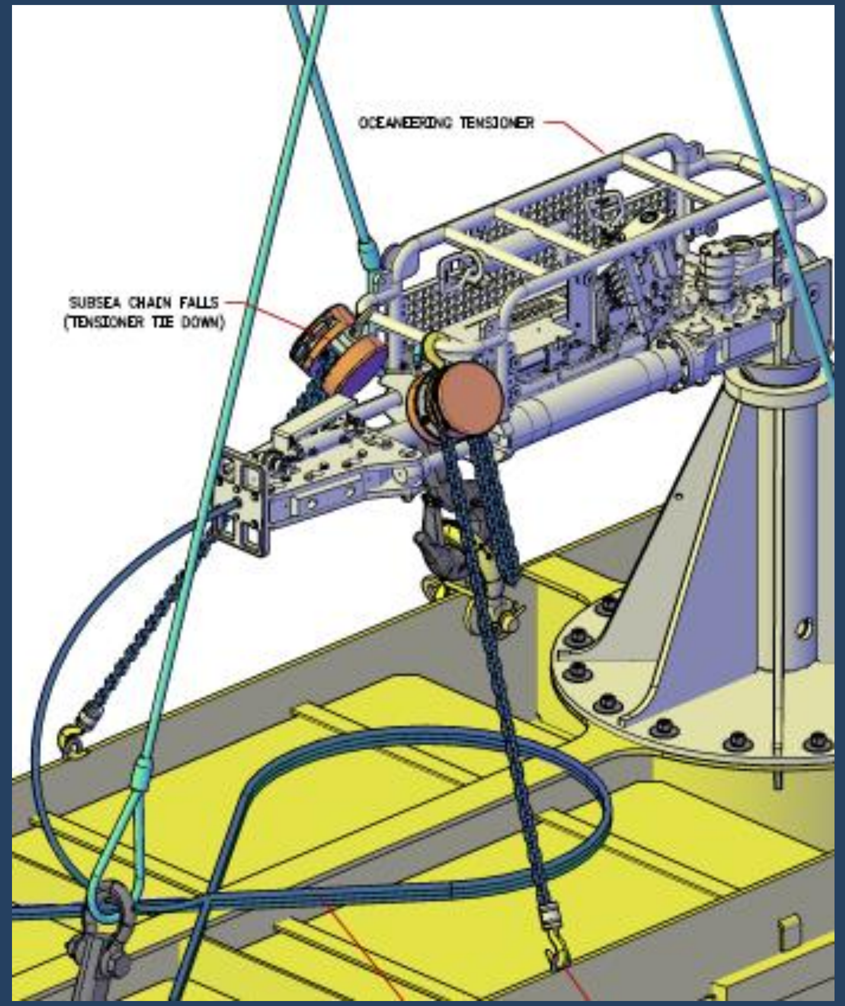
Wellhead Fatigue

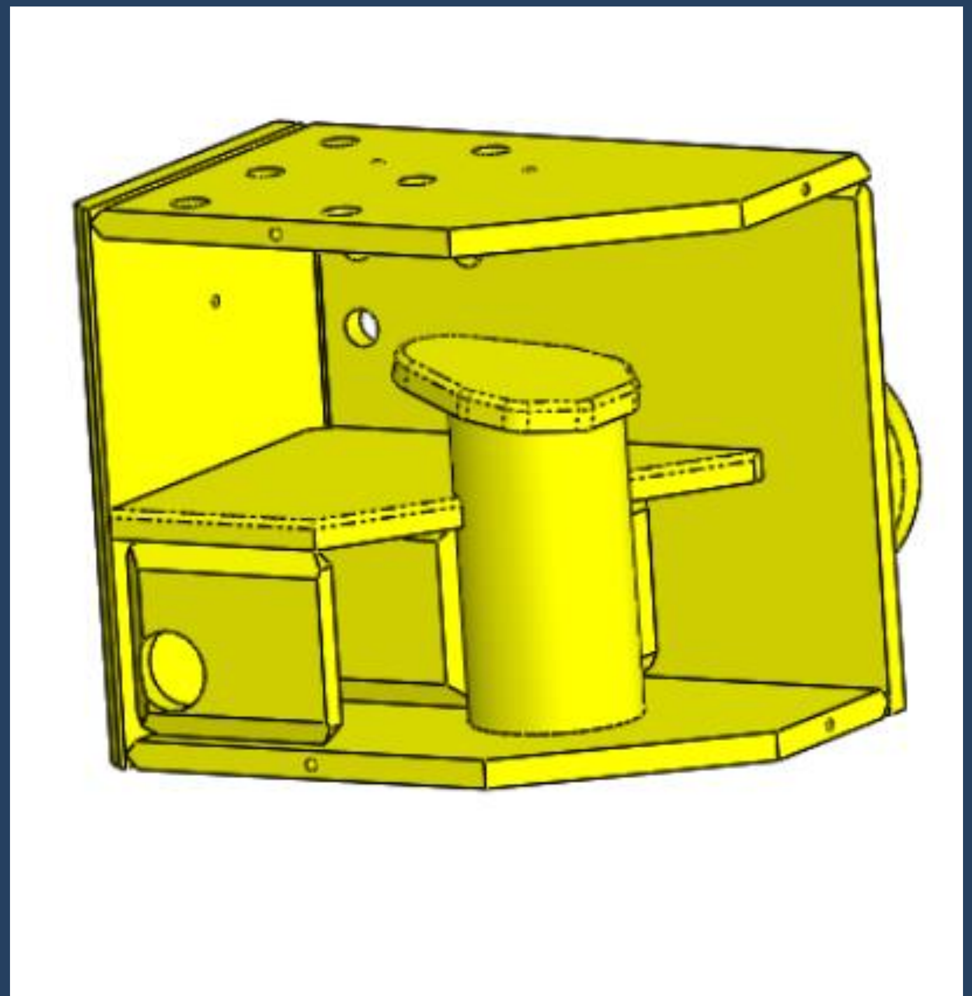
- *Old well judged to have insufficient fatigue life left*
- *Require BOP tethering*

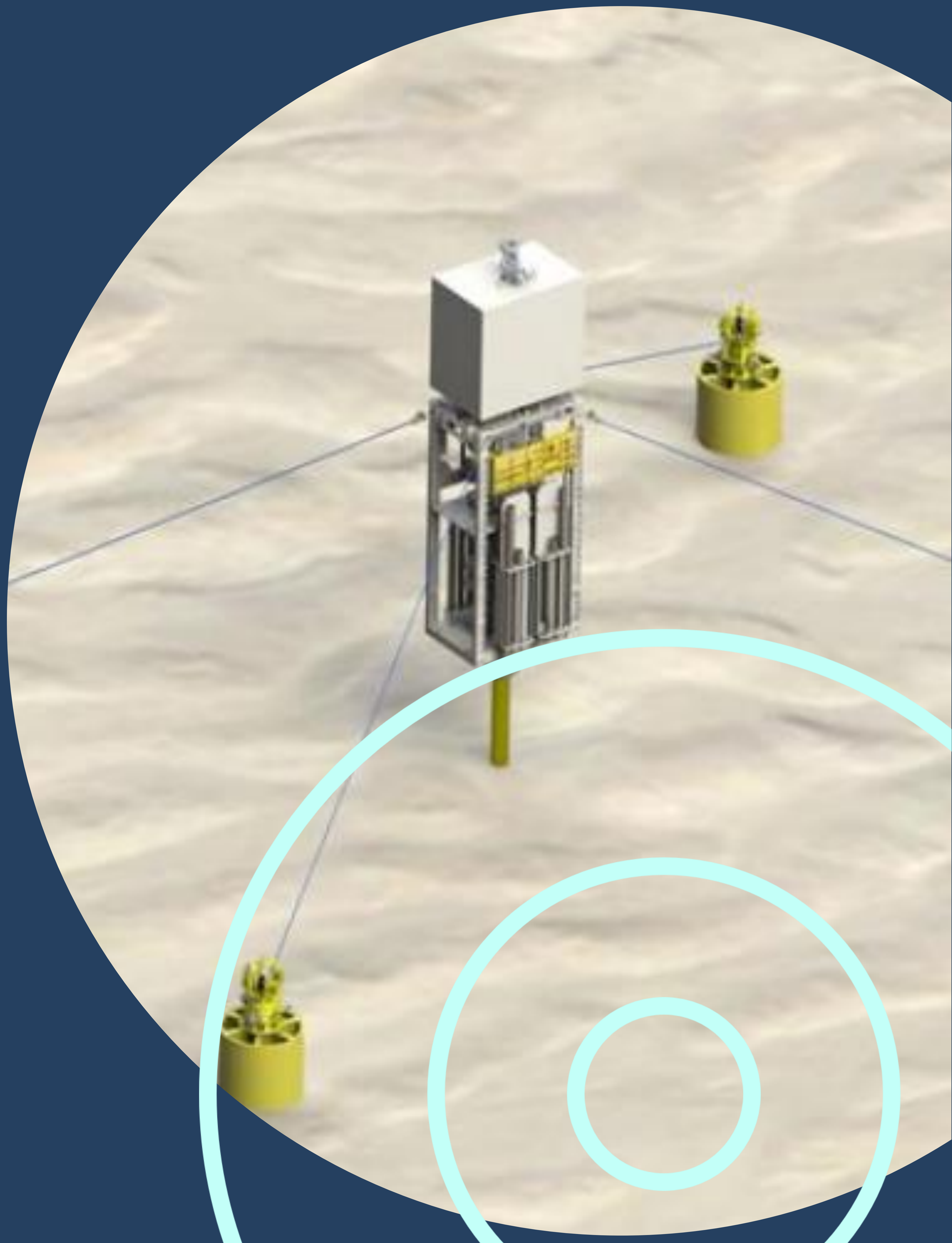




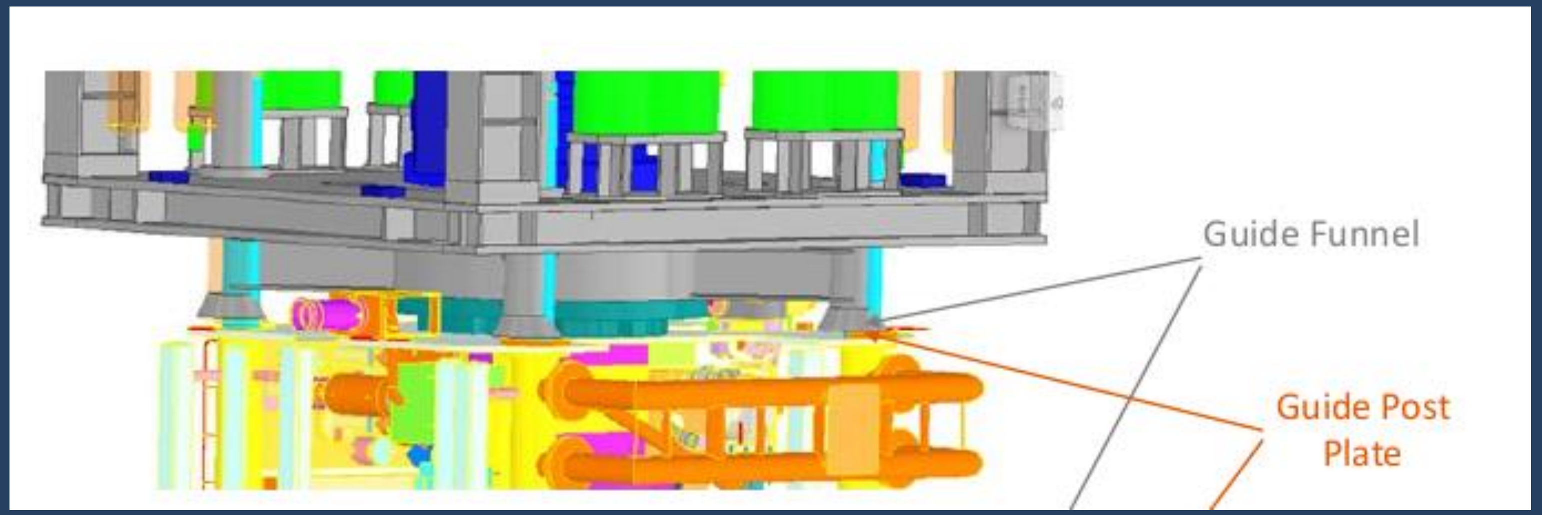


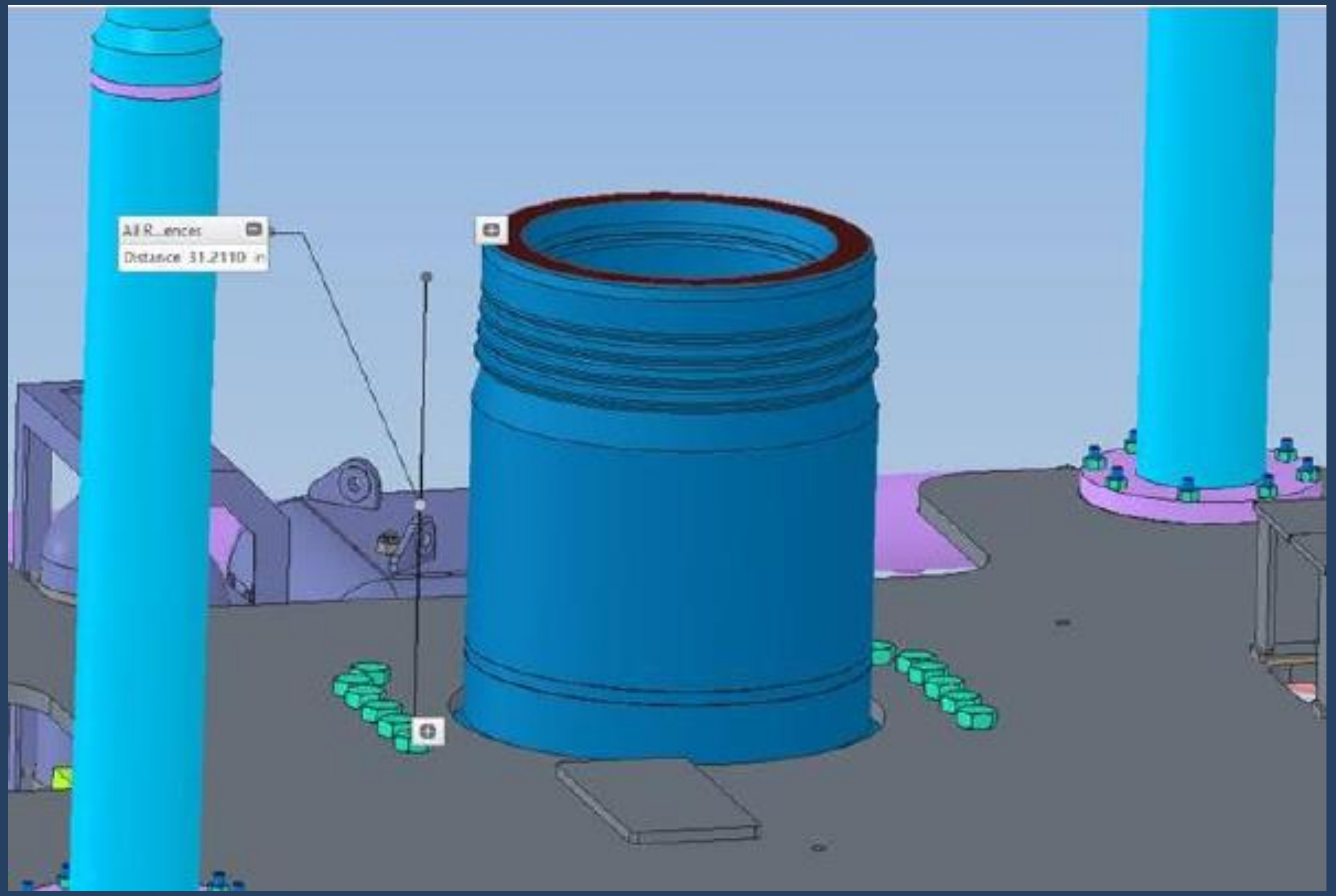


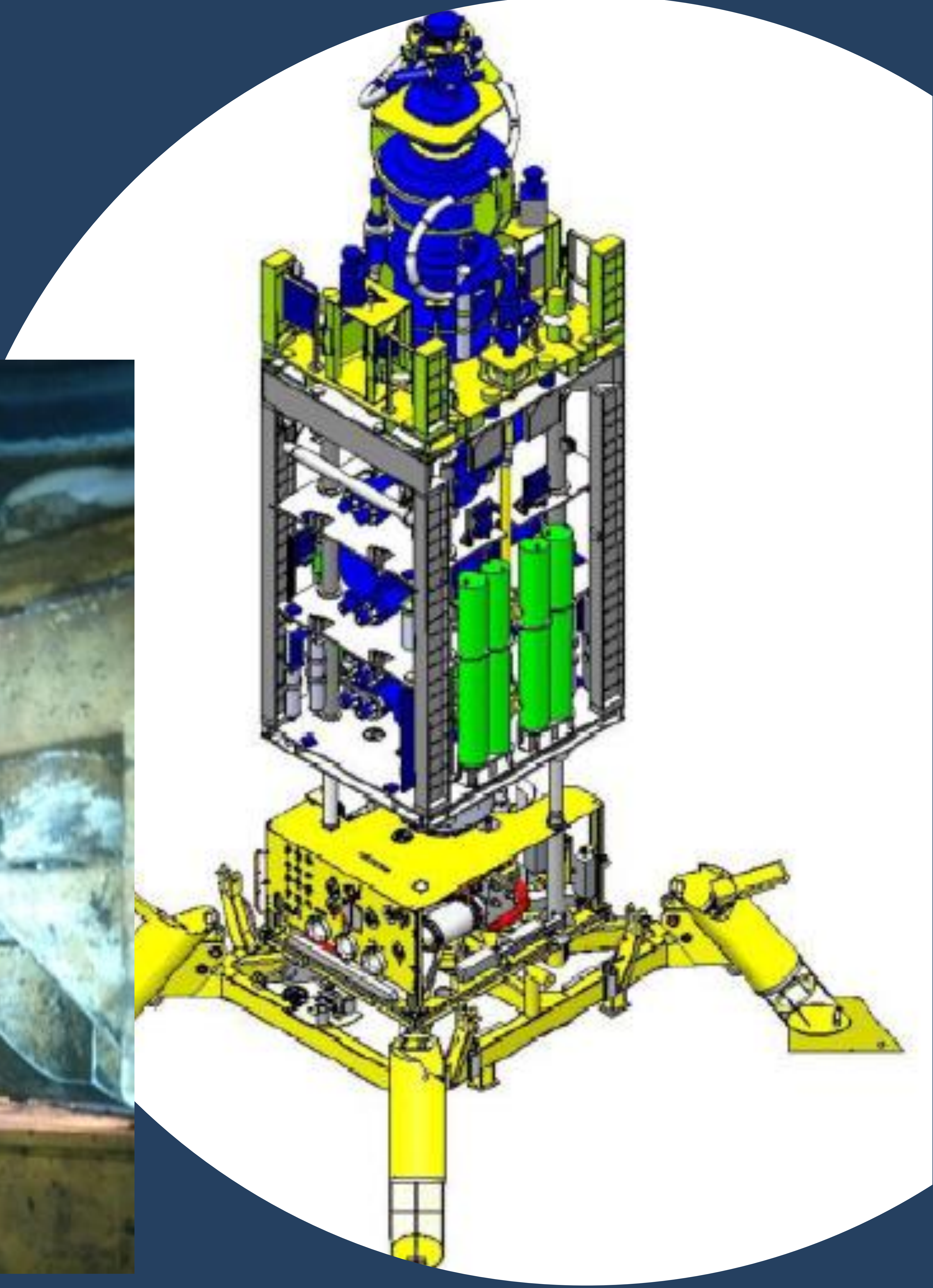




Interface between Xmas Tree and BOP Wellhead Connector





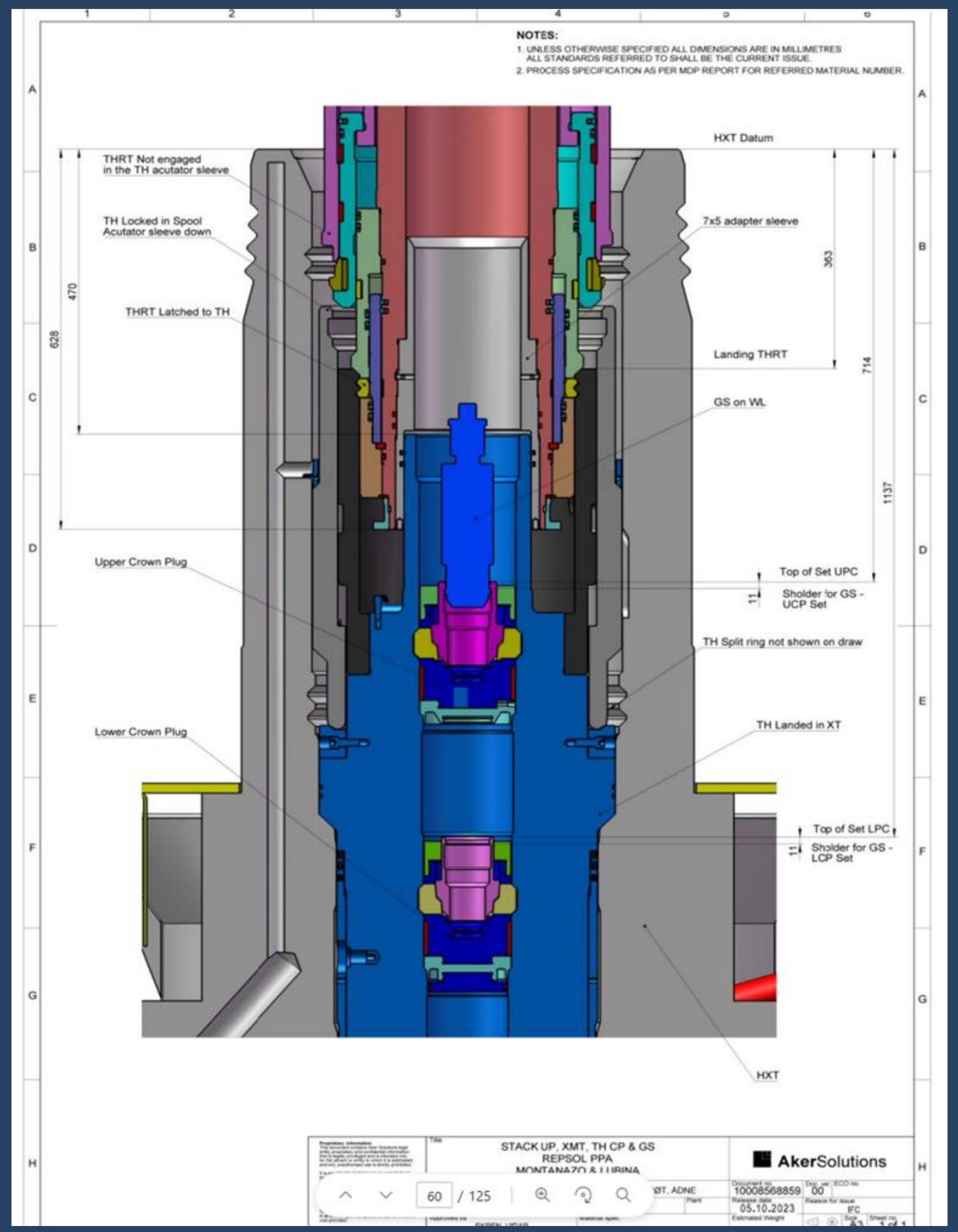


BOP testing options.

In many P&A operations, it is not possible to perform a full BOP test due to equipment installed within the subsea HXMT and a test dispensation is sought with a BOP to XT connector test only being performed

		HARDWARE IN PLACE				BOP COMPONENTS THAT CAN BE PRESSURE TESTSED							
		HXMT	TUBING HANGER	TUBING HANGER BORE PROTECTOR	CLS/SSTT	UAP	LAP	BSR	CSR	UPR (3 1/2" -7 5/8" VBR)	MPR (9 5/8" CASING RAM)	LPR (3 1/2" -7 5/8" VBR)	COMMENT / RISK
API STD 53 BOP INITIAL BOP PRESSURE TESTING ON LANDOUT	ON BOP INITIAL LANDOUT	🟢	🟢	🔴	🔴	🔴	🔴	🟢	🔴	🔴	🔴	🔴	BOP connector test between BSR and Upper Crown Plug
	ON BOP INITIAL LANDOUT WITH MRT TOOL & 20ft 5 " DP PUP	🟢	🟢	🔴	🔴	🟢	🟢	🔴	🔴	🟢	🔴	🟢	No emergency unlatch capability for the duration of the BOP test. Standard operating procedure of 2.5 turns for release.
	Completion Landing String in Place with SSTT	🟢	🟢	🔴	🟢	🟢	🔴	🔴	🔴	🔴	🟢	🔴	UAP required to pressure up to XXXXpsi if emergency unlatch activation required.
API STD 53 BOP SUBSEQUENT BOP PRESSURE TESTING	Completion Landing String / SSTT and Tubing Hanger / Completion pulled. HXMT TEST PLUG & 25FT 5" DP PUP.	🟢	🔴	🟢	🔴	🟢	🟢	🔴	🔴	🟢	🔴	🟢	Tubing hanger bore protector only required if contingency section milling planned.
	Completion Landing String / SSTT and Tubing Hanger / Completion pulled. HXMT SPOOL ISOLATION TEST TOOL (XT ITT) & 30FT 5" R2 DP JOINT.	🟢	🔴	🔴	🔴	🟢	🟢	🔴	🔴	🟢	🔴	🟢	No requirement for installing tubing hanger bore protector if no string rotation planned.

16th August 2024



Cement, Managing the risk of gas

Gas flow measured at a rate of 0.5 litre/hour.

Low Probability High Impact Events – what is the right level of contingency?

What shapes the contingency strategy?

Remove future liability

Balance of likelihood, impact and cost

Viable options for worst case scenarios

Potential Contingency Options

Scenarios

Casing leak above plug #4 – potential exit point

Large gas accumulation under plug #4

Flowing gas charge into plug #4?

Casing Leak below plug #4 – establish integrity

Poor cement outside 13-3/8" casing

Relief well not viable

Retrieve BOP

Bizmuth / Seal-tite

Casing Patch

ACP

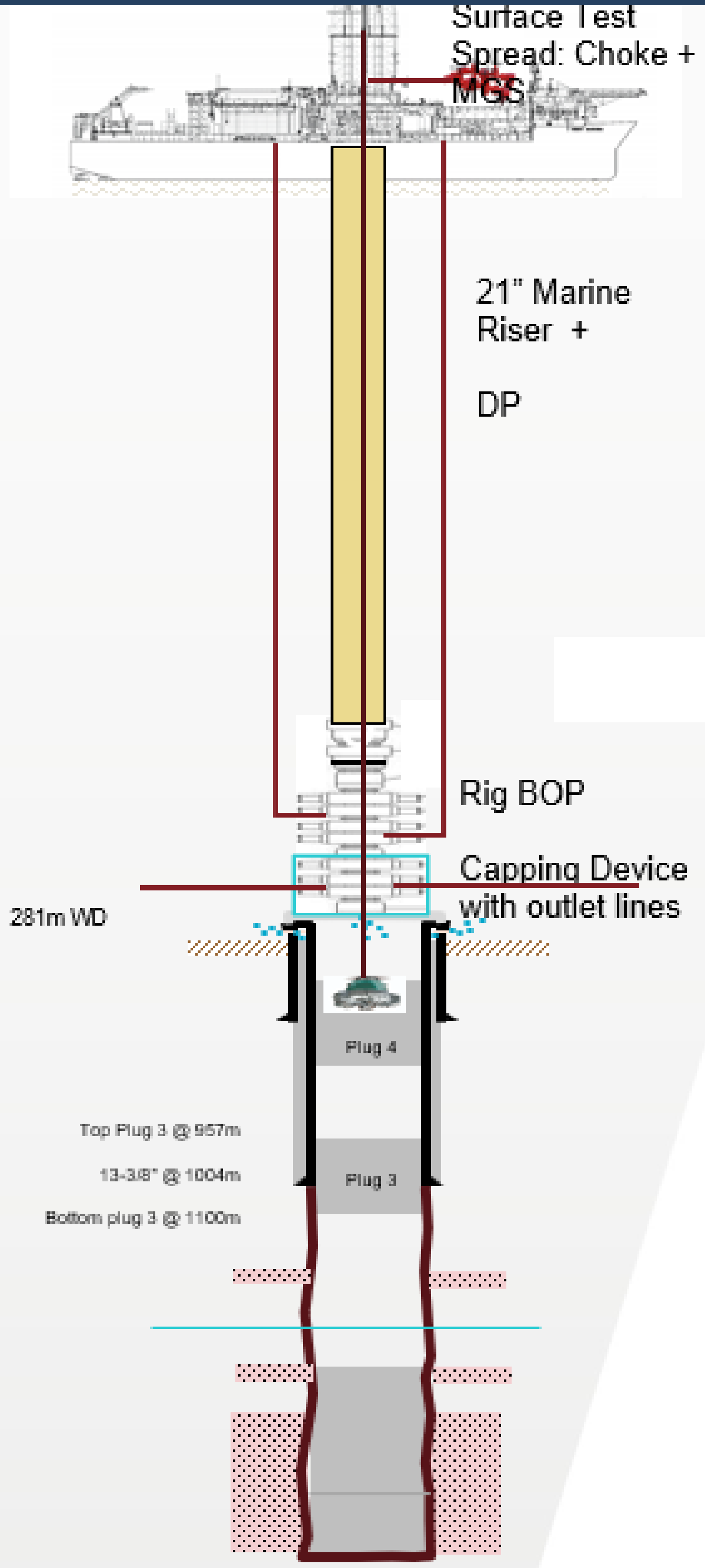
Surface Bleed-off package

Coiled Tubing Drilling

Scab Casing (set deep) + ACP

PWC

Subsea Closure Device



Blowout Contingency Plan

Relief Well Unfeasible

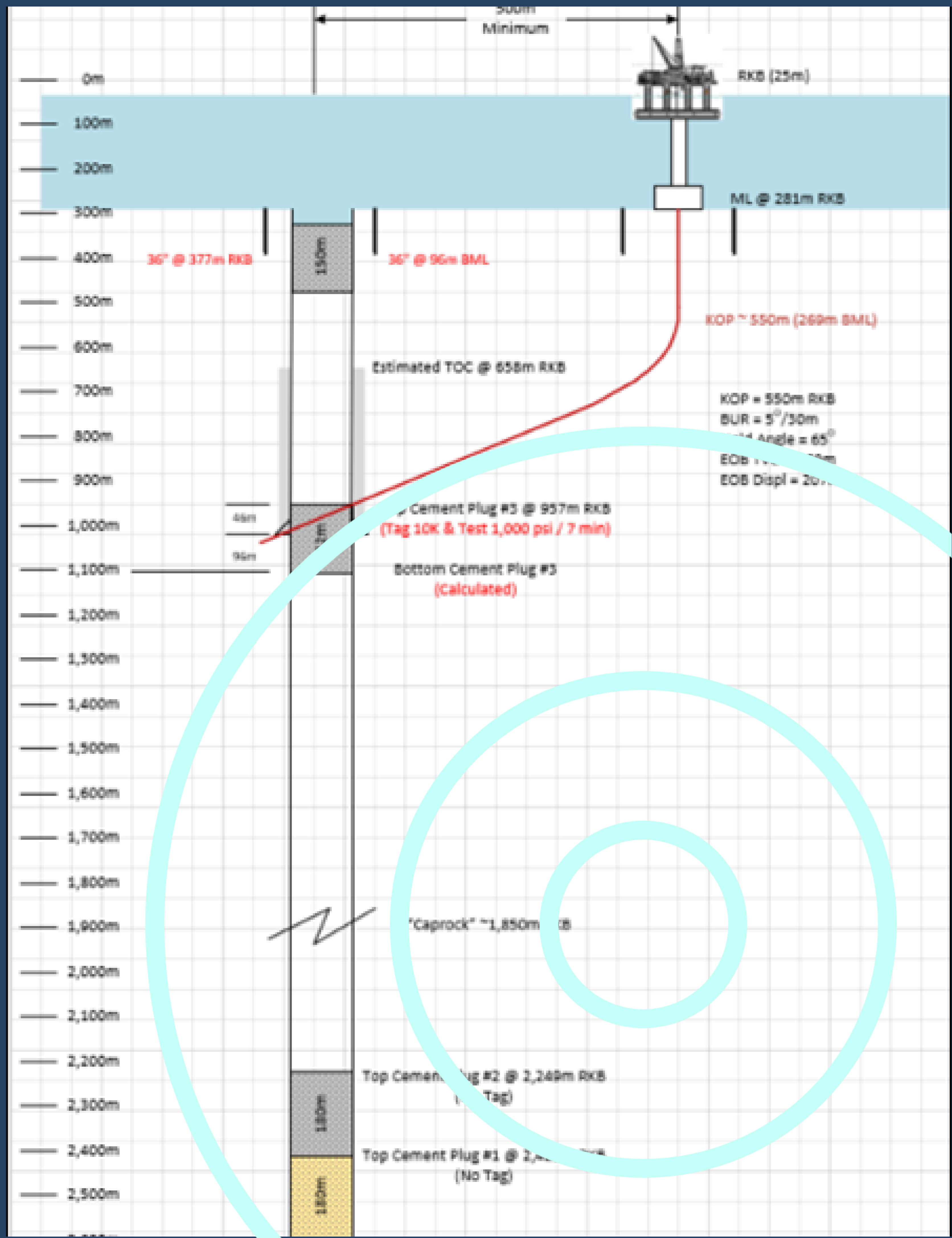
Blowout contingency plan required (NORSOK D010, other standards)
Relief well intersection and kill too challenging to be feasible

- WWC: 'Directional control and hole stability at the extreme angles required to affect the intercept are not considered feasible'
- WWC (considered shoe strength without modelling) and AddEnergy (modelled high blowout rate and kill) both aligned that the 13-3/8" shoe is too weak for a well kill to be considered feasible.

How can the lack of a feasible relief well be adequately mitigated?

Ability to close in (cap) a blowing well below the BOP	Facilitate safe removal of BOP, if damaged	Allow a rig to re-enter the well and continue P&A operations

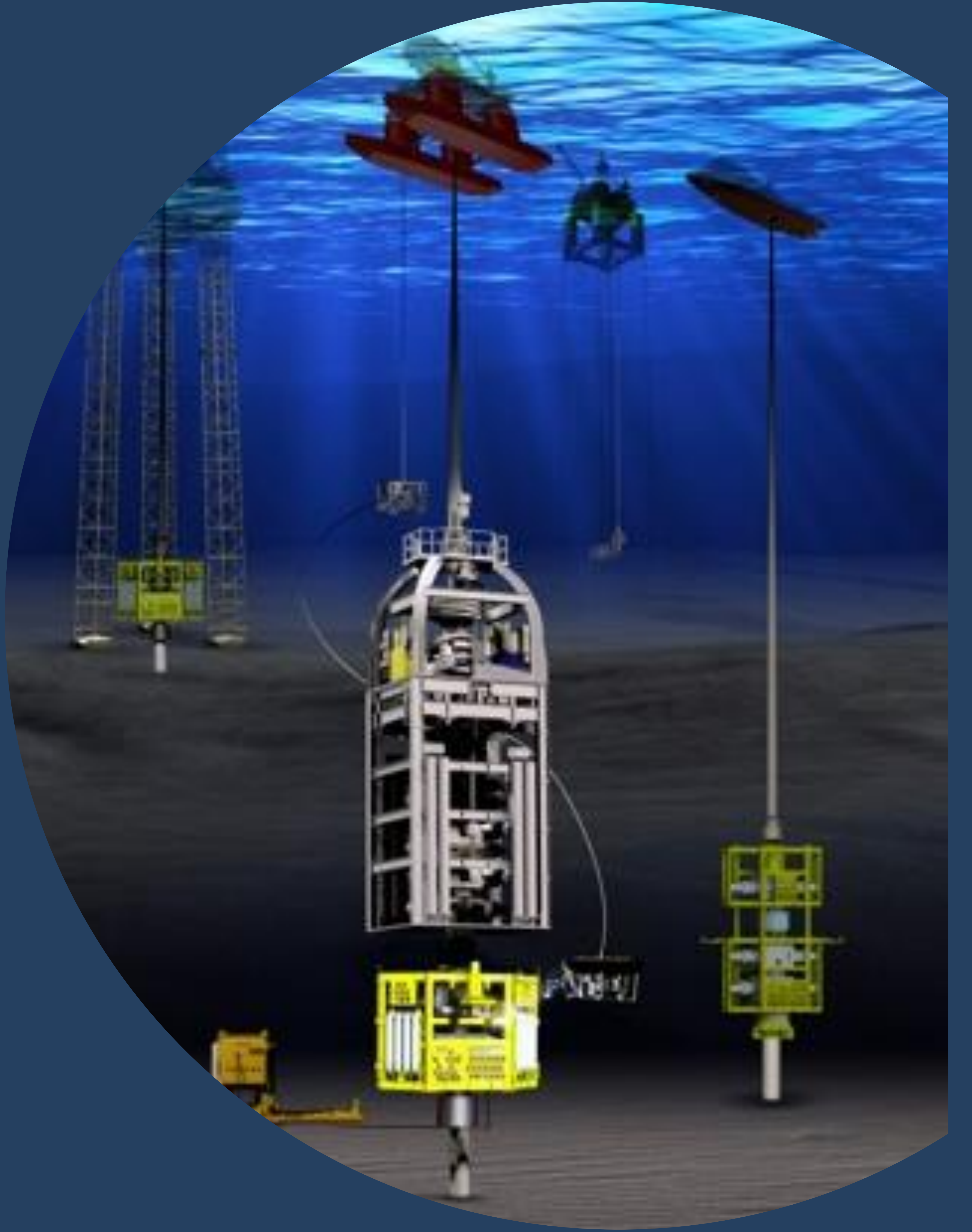
Pre-installation of a subsea closure device below the BOP (capping-type device)



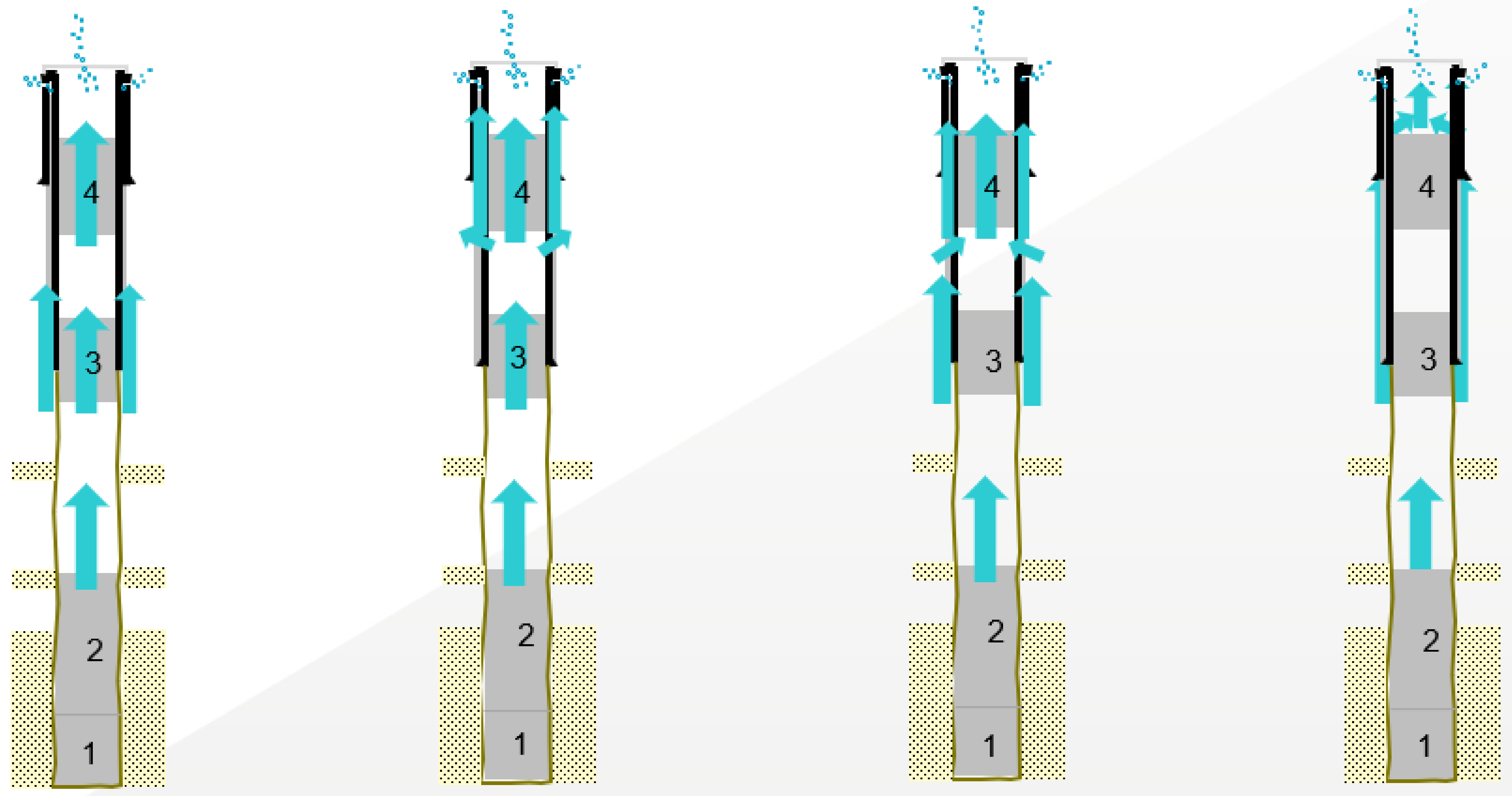
MCD - Mudline Closure Device

Design

- Supplied by Trendsetter
  - *DX connector on bottom*
  - *2 x Low Force Shear Rams*
  - *Side outlets between rams*
    - *Failsafe valves*
    - *Cement return line to seabed*
    - *Blowout diversion line*
- Acoustic/electro-hydraulic control system independent from rig control system.
  - *ROV hot stab*
  - *Subsea accumulator module*
- **Not** part of rig EDS or emergency shut in
  - *Rig BOP used in emergency*
  - *MCD used thereafter to secure well if required*
- Size optimised to mitigate fatigue modelling concerns
- Plume modelling performed to understand effects of various gas discharge scenarios at seabed and define outlet line requirements



Possible Gas Migration Routes



Both plugs & 13 ⅜” annulus cement leaking

Both plugs & 13 ⅜” casing below plug 4 leaking

13 ⅜” annulus cement & 13 ⅜” casing below plug 3 and plug 4 leaking

13 ⅜” annulus cement & 13 ⅜” casing above plug 4 leaking

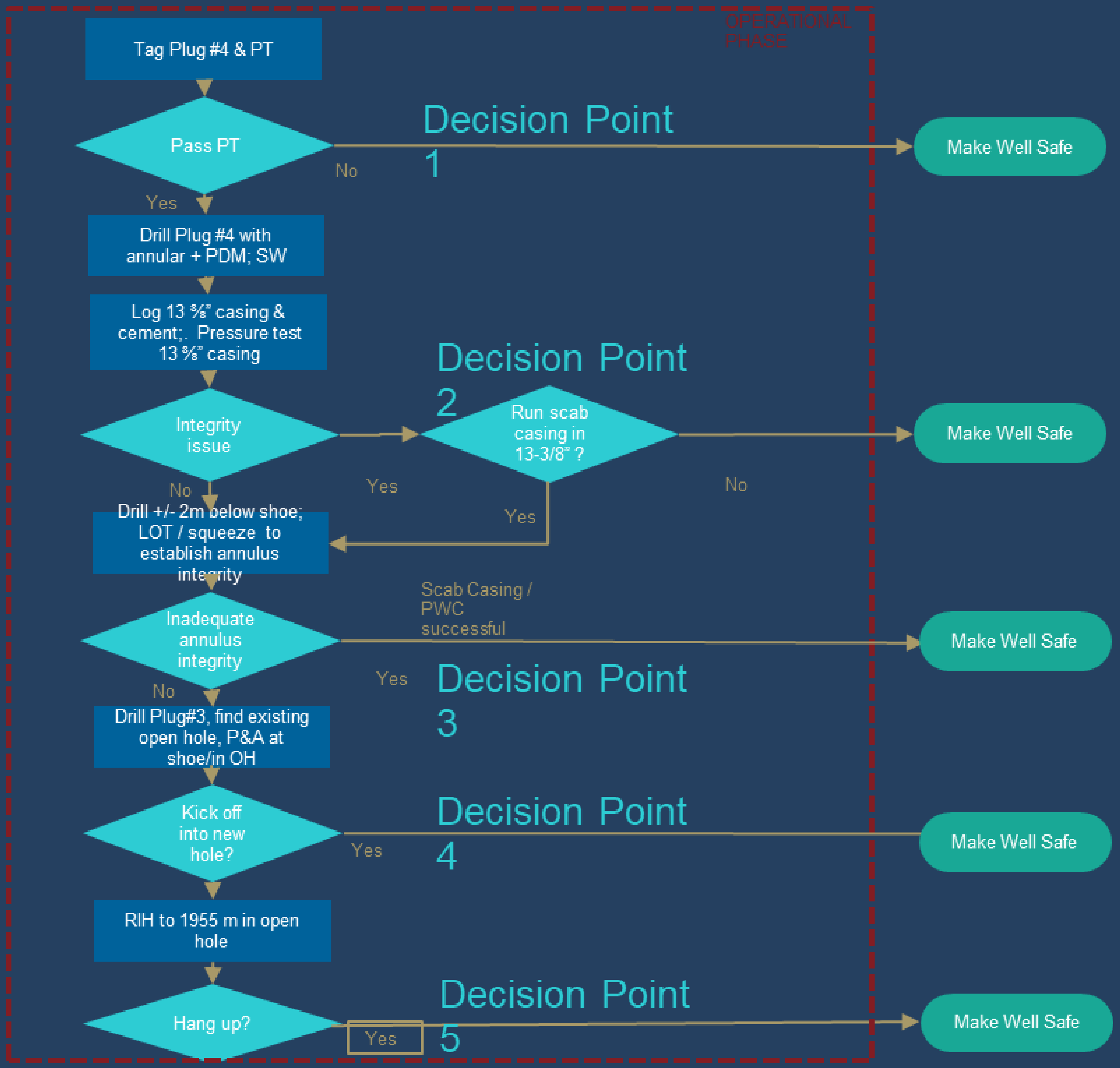
- Multiple possible gas migration routes resulting in several potential well integrity issues with consequential high-risk hazards during the different stages of the planned P&A work.

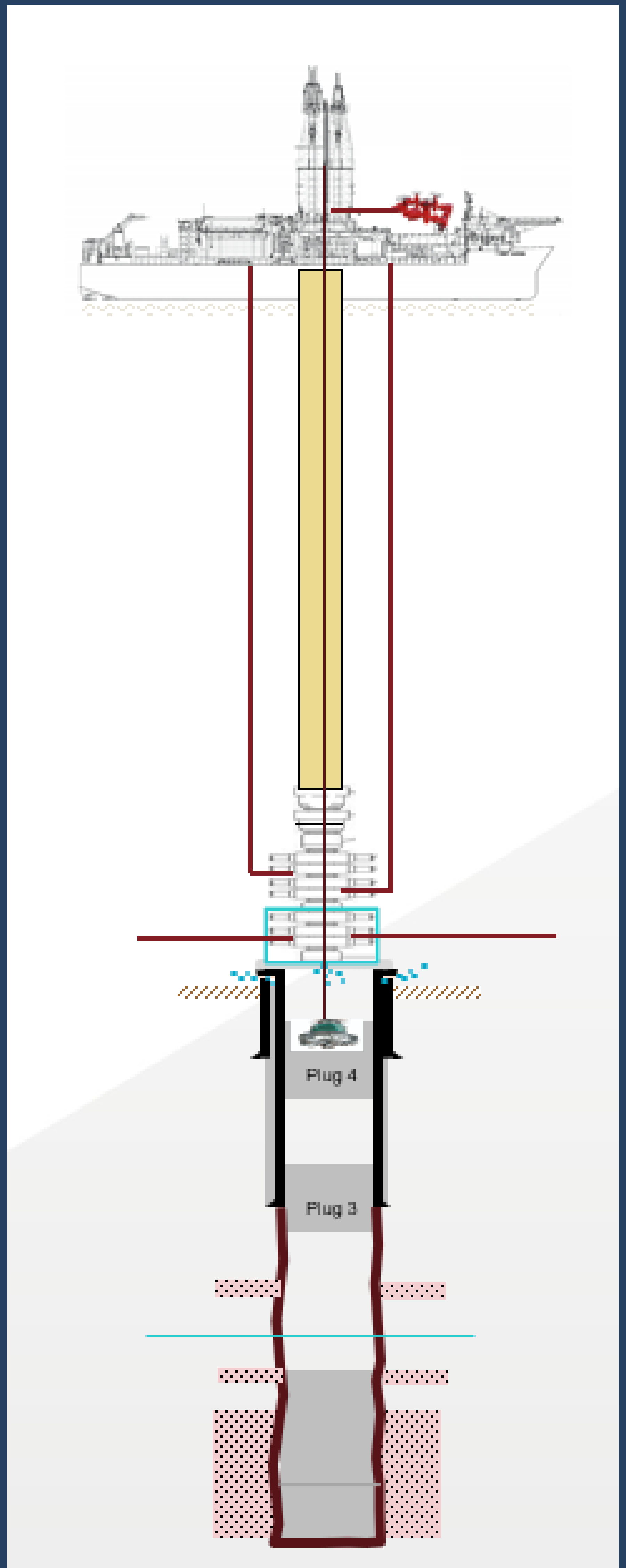
- As a result, we may need to cease P&A operations at various points in the operations and make the well safe

→ ***Banda-1 Regulatory Roadmap***

- Pre-agreed way forward at key
- decision points

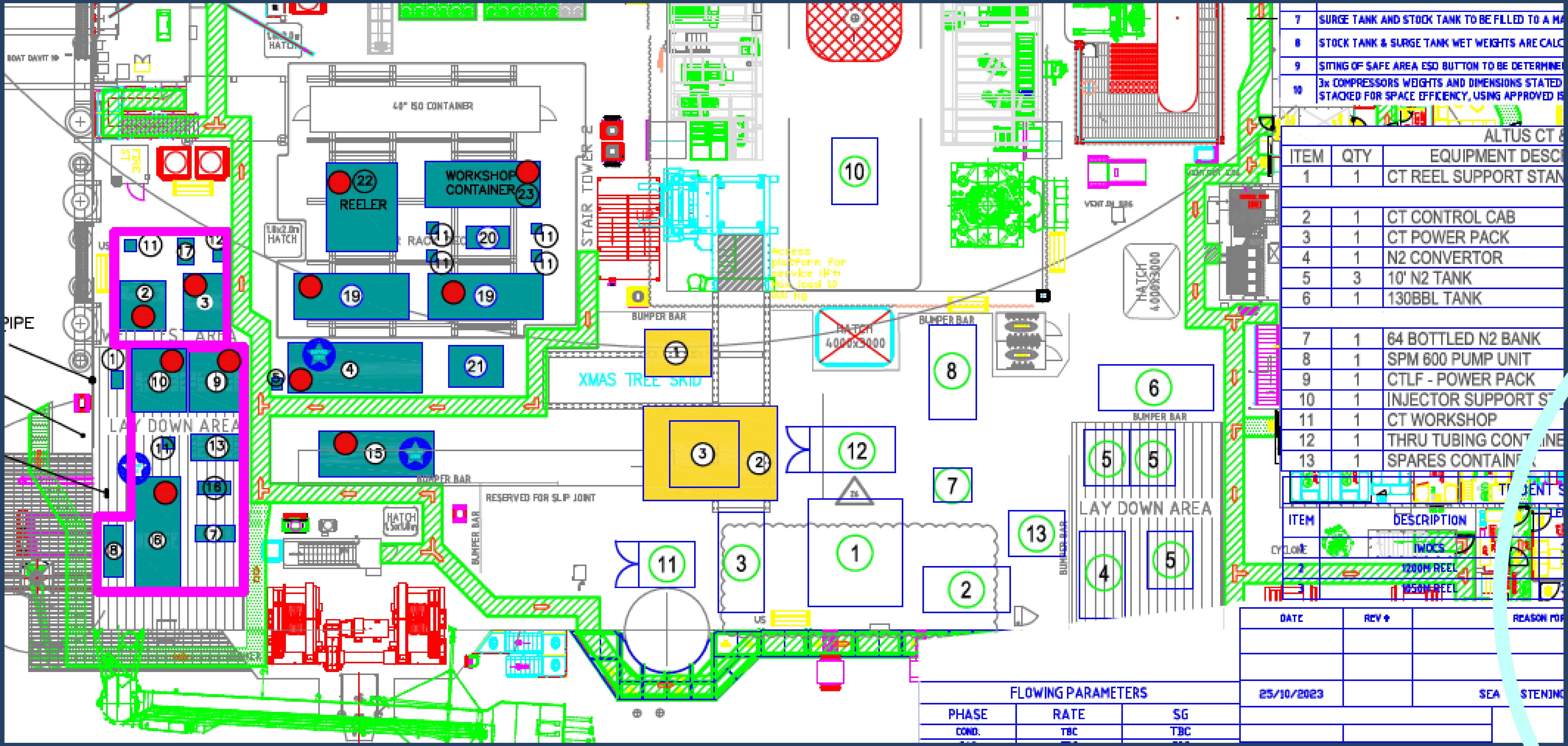
Operations Decision Tree





Equipment

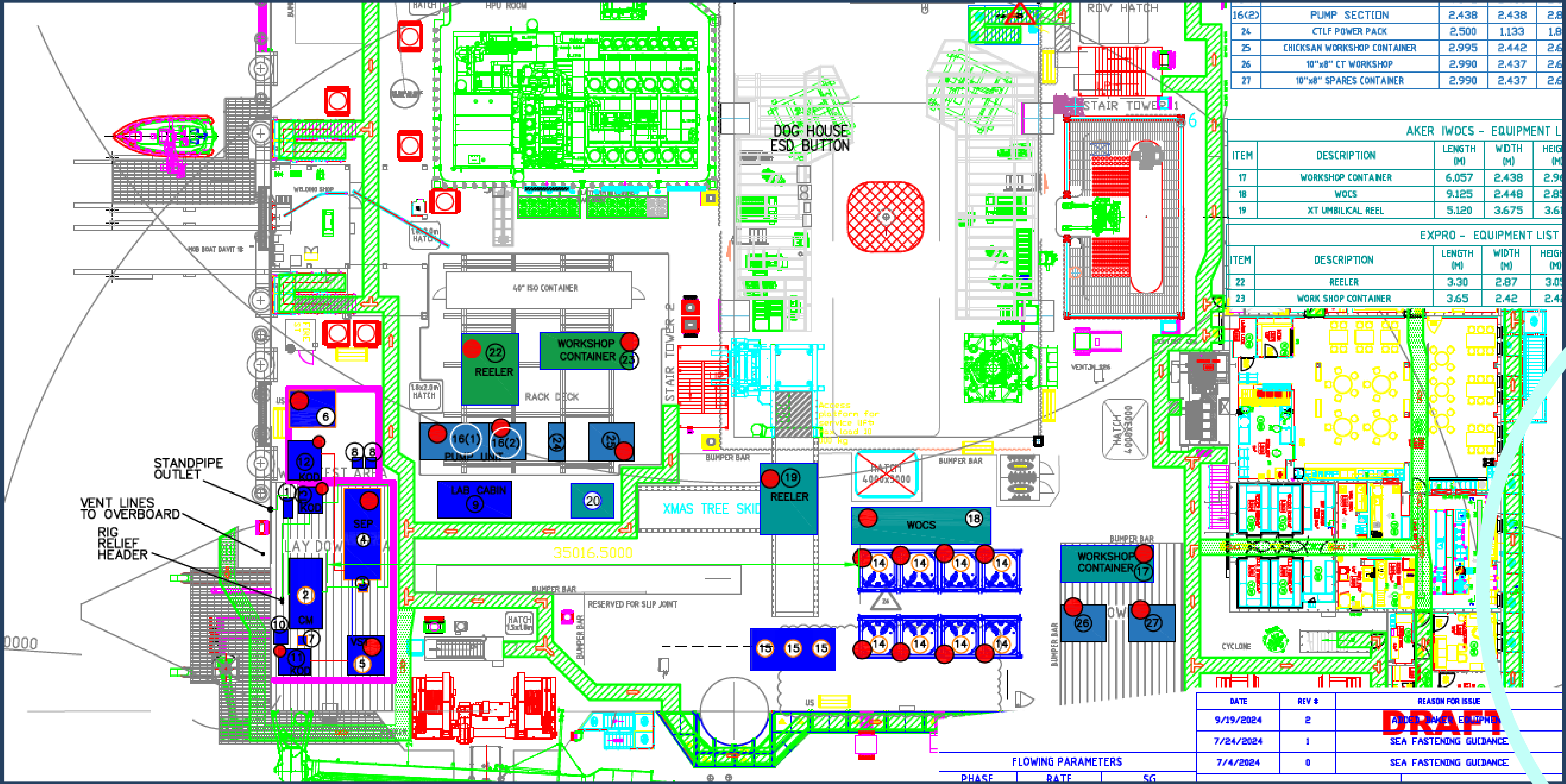
Previous layout



Equipment

Equipment

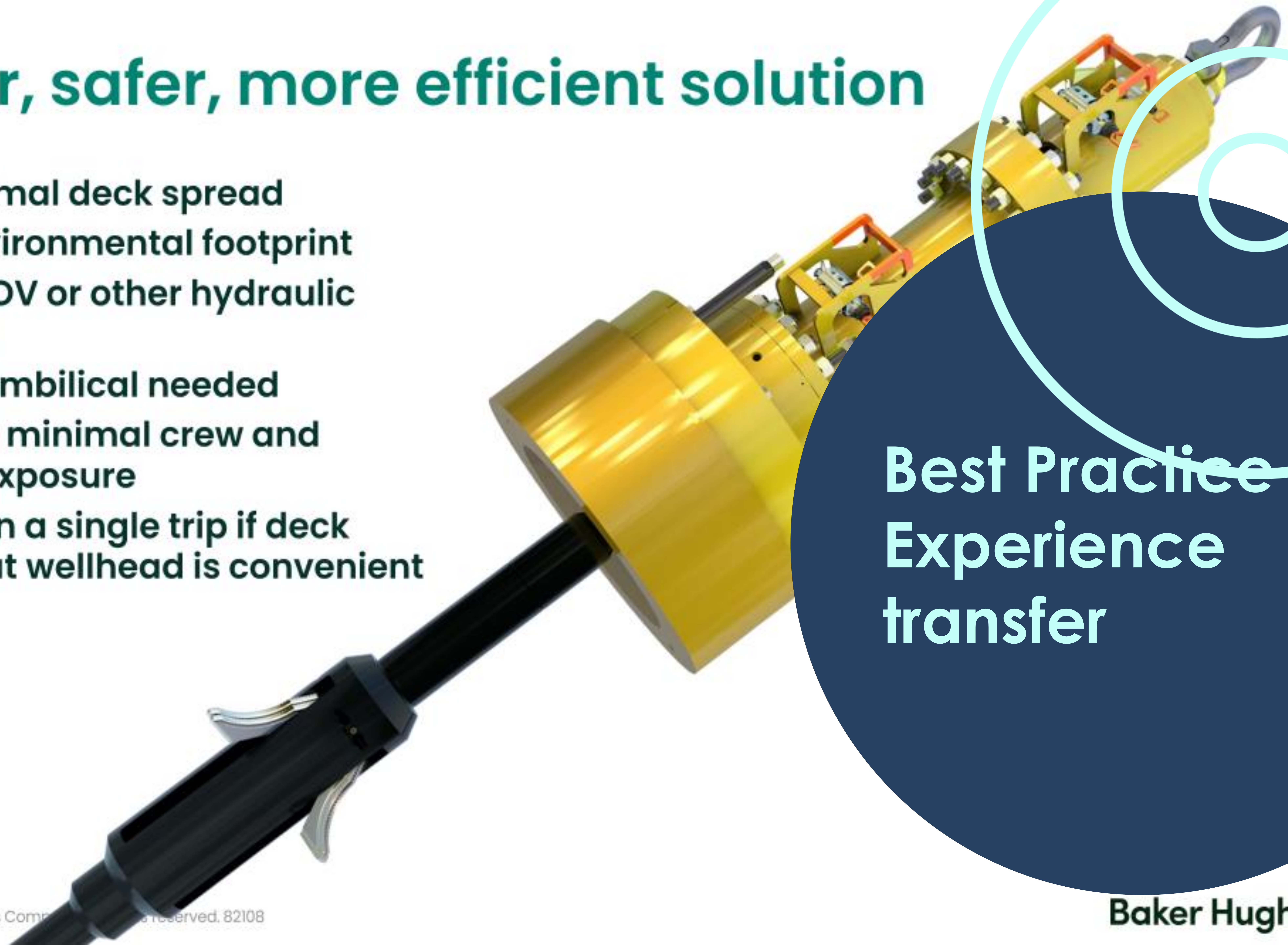
Planned Layout



The Solution

A simpler, safer, more efficient solution

- Requires minimal deck spread
- Minimizes environmental footprint
- Powered by ROV or other hydraulic power source
- No separate umbilical needed
- Operates with minimal crew and reduces HSE exposure
- Can be done in a single trip if deck handling of cut wellhead is convenient



Best Practice Experience transfer

Island Innovator - Multi Rig Consept

Rig owner
Contract holder
Rig Management
DOC Holder
Lead consortium
Planning & performing rig operations in consortium

Well Service , Subsea installation & well access systems
Planning all subsea operations in consortium

Well Service operations
Planning well logging & CT operations in consortium

Riserless Drilling
Mud recovery
MPC – Managed Pressure drilling
CTS – Cutting Transportation

Casing and tubing service
Support Drilliing personnel

Multi rig Contept

Riserless
D&Wi

Wireline	Slot recovery
P&A	Coiled Tubing

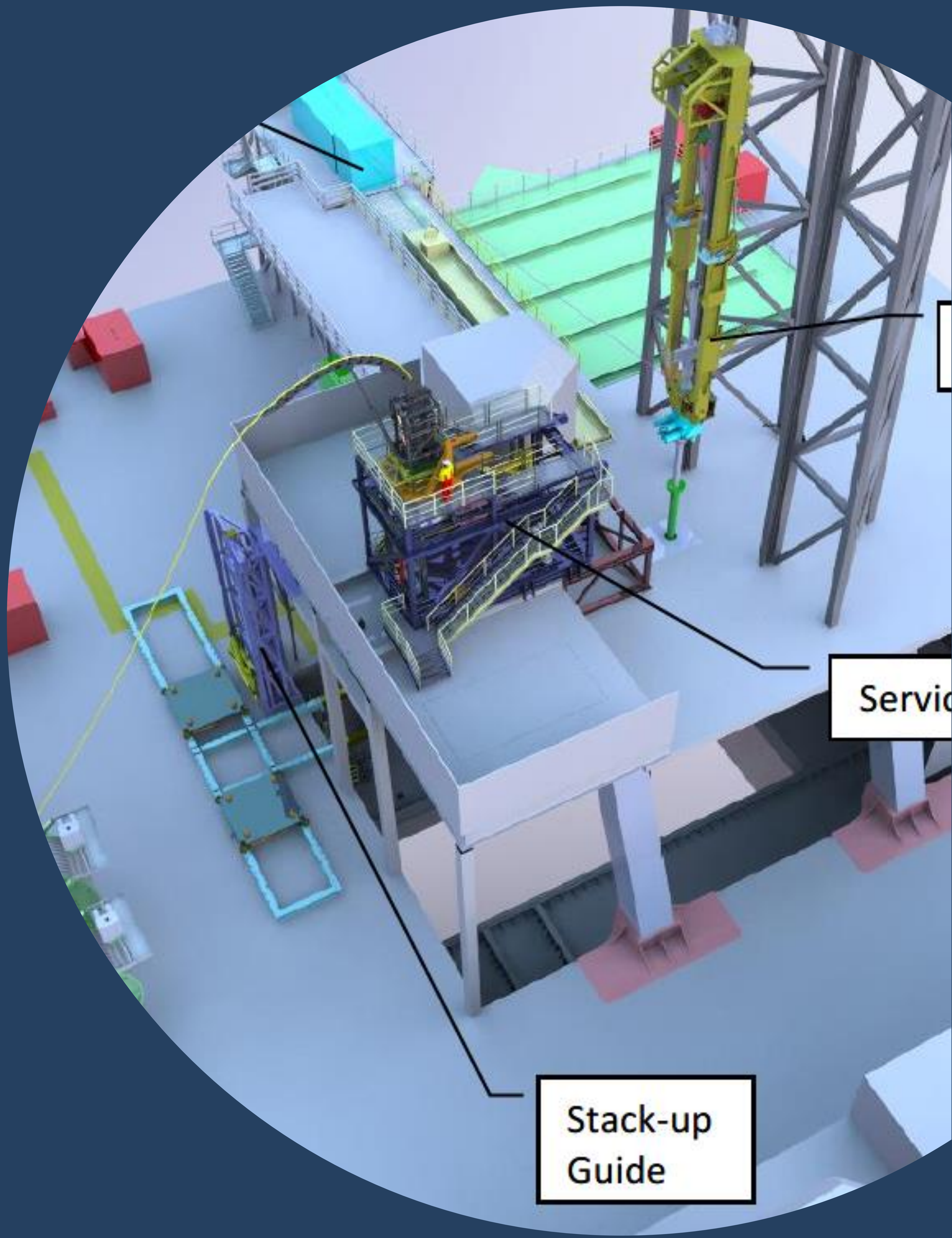
Drilling & Re Completion


Intervention, Drilling, P&A

Riser based
D&Wi

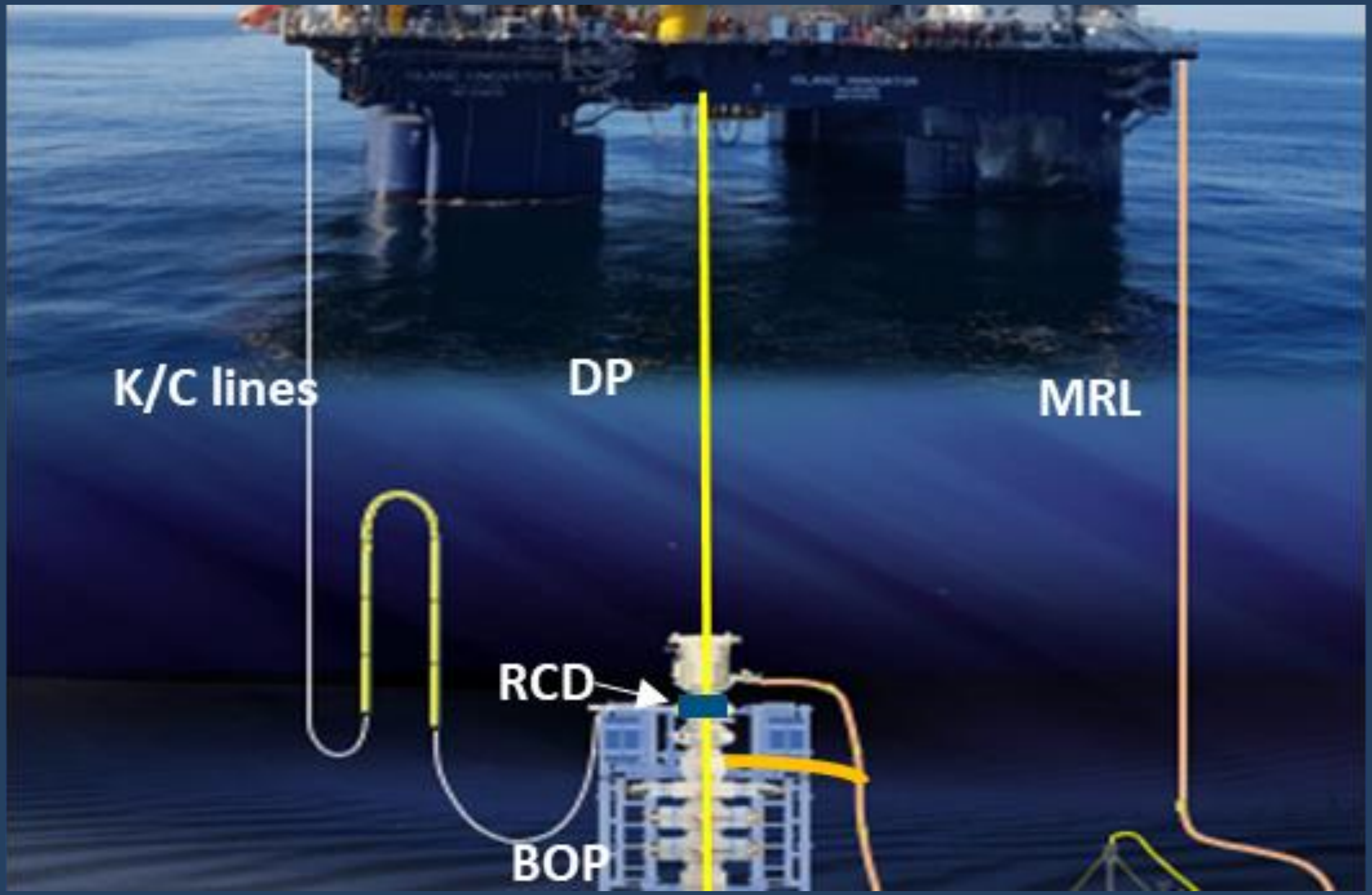
Wireline	Slot recovery
P&A	Coiled Tubing

Drilling & Re Completion



Island Innovator

Multi Rig Consept



- ➢Safer
- ➢More efficient
- ➢Fully automated
- ➢No Wellhead Fatigue
- ➢Greater operability
- ➢Reduced Carbone footprint
- ➢Reduced POB
- ➢Reduced Cost

Thank you for the attention