MITIGATING THE ROOT CAUSE OF HIGH OFFSHORE WELL P&A

REFERENCE: OILtd-DTD-16-08-07-001

Issued: 07/08/2016

PURPOSE: Analysis

PRODUCT: Downhole Tubing Disposal

Document approval

revision	date	written by	approved by
1	26 / 06 / 2016	B. TUNGET	C. SMITH
2	27 / 06 / 2016	B. TUNGET	C. SMITH
3	04 / 08 / 2016	B. TUNGET	C. SMITH
4	07 / 08 / 2016	B. TUNGET	C. SMITH

Classification

unclassified	X	internal		restricted		confidential	

Distribution List

Name	hard copy	electronic copy
Clint Smith and Vegar Haraldsen, Oilfield Innovations Limited		X
Dr. Angela Seeney, Oil & Gas Authority	X	X
Bill Cattanach, Oil & Gas Authority	X	X
Sylvia Buchan, Oil & Gas Authority	X	X
John Youles, Oil & Gas Authority	X	X
Colette Cohen, Oil & Gas Technology Centre (OGTC).	X	X
Alasdair MacDonald, ConocoPhillips		X
Dr Lindsay Wilson, Oil & Gas Innovation Centre		X
Dr Tom Leeson, Reverse Engineering Services		X
Matthew Marcantonio, Claxton Engineering		X
Danny Claxton, Claxton Engineering		X
Les Burr, Westerton UK Limited		X
John Davidson, GE Oil & Gas		X

Document Classification Level	Definition
Unclassified	Information that may be made public without consequences for the entity or Oilfield Innovations Limited (OILtd).
Internal	Information intended to remain within the Oilfield Innovations Limited. Permission from a Director of OILtd is required to disclose it outside OILtd.
Restricted	Information that can be disclosed outside of OILtd only if approved by a Director of Oilfield Innovations Limited as it could have serious impact on OILtd. Access is limited to specific addressees identified herein.
Confidential	Information that can only be distributed only if the addressee has a confidentiality agreement with OILtd whereby disclosure could have a major impact on OILtd. In such cases, very strict rules apply to dissemination.

Table of Content

List of Tables

ABBREVIATIONS

Table 1 - Abbreviations

Acronym	Definition
ABX	Abandonment Expenditure
API	American Petroleum Institute (API) is a U.S trade association for the oil and natural gas industry. It represents corporations involved in production, refinement, distribution, and many other aspects of the petroleum industry.
BOP	Blowout Preventer. A blowout preventer (BOP) is a large, specialized valve or similar mechanical device, used to seal, control and monitor oil and gas wells to prevent blowout, the uncontrolled release of crude oil and/or natural gas from well. They are usually installed redundantly in stacks and act as a secondary barrier.
HWU	Hydraulic Workover Unit. Well intervention equipment using hydraulic cylinders to install or remove tubulars from dead wells. A "dead" well is a well that does not flow when exposed to atmospheric pressure. When additional blowout preventers (BOPs) are added to an HWU it can be converted to a “Snubbing Unit” configured to open and close blowout preventers with intermediate bleeding of pressure between preventers to allow installing or removing tubulars with a “live” well that is capable of flow when exposed to atmosphere.
LSA	Low Specific Activity (LSA) material, see NORM.
NORM	Normally Occurring Radioactive Material (NORM), also known as Low Specific Activity (LSA) material, is the term used to describe radioactive materials that exist naturally in the geological environment. NORM occurs in small quantities in the oil and gas industry and builds up within the production tubing and components in much the same way as natural lime scale develops in a kettle over a period of time.
NUI	Normally Unmanned Installation. Small offshore jacket and topsides used to reduce the cost of development for smaller or lower value hydrocarbon deposits.
O&G UK	Oil and Gas UK, is a United Kingdom trade association for the oil and natural gas industry. It represents corporations involved in production, refinement, distribution, and many other aspects of the petroleum industry
OGA	United Kingdom Oil and Gas Authority
OILtd	Oilfield Innovations Limited, author of the present analysis and a small limited liability company who promotes new oil and gas technologies
PWC	Perf and Wash Casing (PWC) method. See Section C.4.3.
TRL	Technology Readiness Level defined by API 17N.

TECHNOLOGY READINESS LEVEL DEFINITIONS

Table 2 - Technology Readiness Levels

Technology Readiness Level	Definition (as defined by API 17N)
TRL-0	Unproven idea/proposal Paper concept. No analysis or testing has been performed
TRL-1	Concept demonstrated. Basic functionality demonstrated by analysis, reference to features shared with existing technology or through testing on individual subcomponents/subsystems. Shall show that the technology is likely to meet specified objectives with additional testing.
TRL-2	Concept validated. Concept design or novel features of design validated through model or small scale testing in laboratory environment. Shall show that the technology can meet specified acceptance criteria with additional testing
TRL-3	New technology tested Prototype built and functionality demonstrated through testing over a limited range of operating conditions. These tests can be done on a scaled version if scalable
TRL-4	Technology qualified for first use Full-scale prototype built and technology qualified through testing in intended environment, simulated or actual. The new hardware is now ready for first use
TRL-5	Technology integration tested Full-scale prototype built and integrated into intended operating system with full interface and functionality tests
TRL-6	Technology installed Full-scale prototype built and integrated into intended operating system with full interface and functionality test program in intended environment. The technology has shown acceptable performance and reliability over a period of time
TRL-7	Proven technology integrated into intended operating system. The technology has successfully operated with acceptable performance and reliability within the predefined criteria

DEFINITION OF WELL ABANDONMENT PHASES

Table 3 - Well Abandonment Phases

Phase	Definition (As defined by IHS®/Rushmore®)
Phase 1	**The abandonment of the reservoir.** The reservoir is defined as the zone from which the well was producing or injecting. This phase covers setting cement plugs to isolate reservoir(s). The tubing may be fully or partly retrieved, or be left in place. Phase 1 starts when beginning to remove the xmas tree, for example rigging up slickline to set plugs for tree removal, or when pumping cement through the xmas tree. Alternatively, for a suspended E&A well, Phase 1 starts when beginning to remove the suspension equipment when installing the first cement plug. Phase 1 is complete when the reservoir is fully isolated from surface.
Phase 2	**The intermediate abandonment.** This phase includes setting cement plugs to contain formation fluids above the reservoir, such as intermediate hydrocarbon or water-bearing permeable zones. It may also include containment of "environmental fluids" (such as oil-based mud) but these "environmental / surface plugs" do not necessarily require formal testing. Where Phases 1 and 2 are done continuously Phase 2 starts when the final Phase 1 cement plug has been installed and verified (if verification takes place) and (if applicable) the verification equipment has been returned to surface. If Phase 2 is not continuous with Phase 1, Phase 2 starts when work begins to remove the suspension equipment (which could be a xmas tree) when installing the first Phase 2 cement plug. Phase 2 is complete when no further plugging is required. It may involve casing retrieval, casing milling, liner isolations, intermediate cement plugs, etc. The tubing may be partly retrieved in this phase, if not done under Phase 1.
Phase 3	**Wellhead and conductor removal.** This phase covers the removal of the wellhead and conductor, and shallow cuts of casing string, and may include any placement of seabed cement to fill resulting craters. Phase 3 starts when picking up the cutting tools to "run in hole", or, if only the removal of tubulars was done, the abandonment work starts when lifting operations begin. Phase 3 ends when the retrieved steelwork is "on deck" and excludes later operations such as ROV surveys and any other "site" abandonment activities. This phase is complete when no further operations are required on well.

DEFINITION OF WELL ABANDONMENT COMPLEXITY / WORK TYPE

Table 4 - Well Abandonment Complexity or Work Type

Complexity or Work Type	Definition (as defined by Oil and Gas UK)
Type 0	**No work required** – A phase or phases of abandonment work may already have been completed
Type 1	**Simple Rig-less Abandonment** - Using wireline, pumping, crane, jacks. Subsea will use Light Well Intervention Vessel and be riser-less
Type 2	**Complex Rig-less Abandonment** - Using CT, HWU, wireline, pumping, crane, jacks. Subsea will use Heavy Duty Well Intervention Vessel with Riser
Type 3	**Simple Rig-based Abandonment** - requiring retrieval of tubing and casing. The Operator may decide to include sub classification of subsea rig based reservoir abandonment to reflect the time and spread differences relating to through tubing, coil tubing or completion pulling operations.
Type 4	**Complex Rig-based Abandonment** – May have poor access and poor cement requiring retrieval of tubing and casing, milling and cement repairs.

1. SUMMARY

The root cause of high well plug and abandonment (P&A) costs can be attributed to:

A) People, Planning, Resources and Competencies that do not question the need for use of a mobile offshore drilling unit (MODU) or do not question the need to refurbish a Platform Drilling Rig,

B) Environmental Constraints above and below Seabed that are more easily addressed by a drilling rig but which can be solved more cost effectively without a drilling rig, albeit more time and planning would be required,

C) Material Volumes, Placement and Disposal Over Specification associated with the capacities of a drilling rig,

D) Method of Removing Downhole Completion Interference and the natural desire to visually see the production tubing and completion, and

E) Machinery Specification resulting in the selection of a Drilling Rig.

The following sections demonstrate the above root causes of high well P&A.

2. OPEN MIND DISCLAIMER

As "*drillers*" with 30+ years of experience, we know the capabilities and limitation of a drilling rig. During our 30+ year careers, we have also been cross-trained in completions and interventions. While are experts in drilling tools, we also know the capabilities and limitations of slickline, wireline and coiled tubing. Drilling rigs are designed for "*drilling*" and not necessarily "*well plug and abandonment*." Slickline, wireline and coiled tubing are designed for thru-tubing operations. Drastically reducing the cost of well plug and abandonment requires an open mind to a slickline, wireline and/or coiled tubing methods, which have been ignored for the following reasons:

i. No one every questions the need for a drilling rig and, therefore, never realise that other equivalent and lower cost methods exist.

ii. It is not in the dominant Service Companies financial interests to change the lucrative status quo and, hence, they continue to use the high time cost of a drilling rig to justify their more costly solutions.

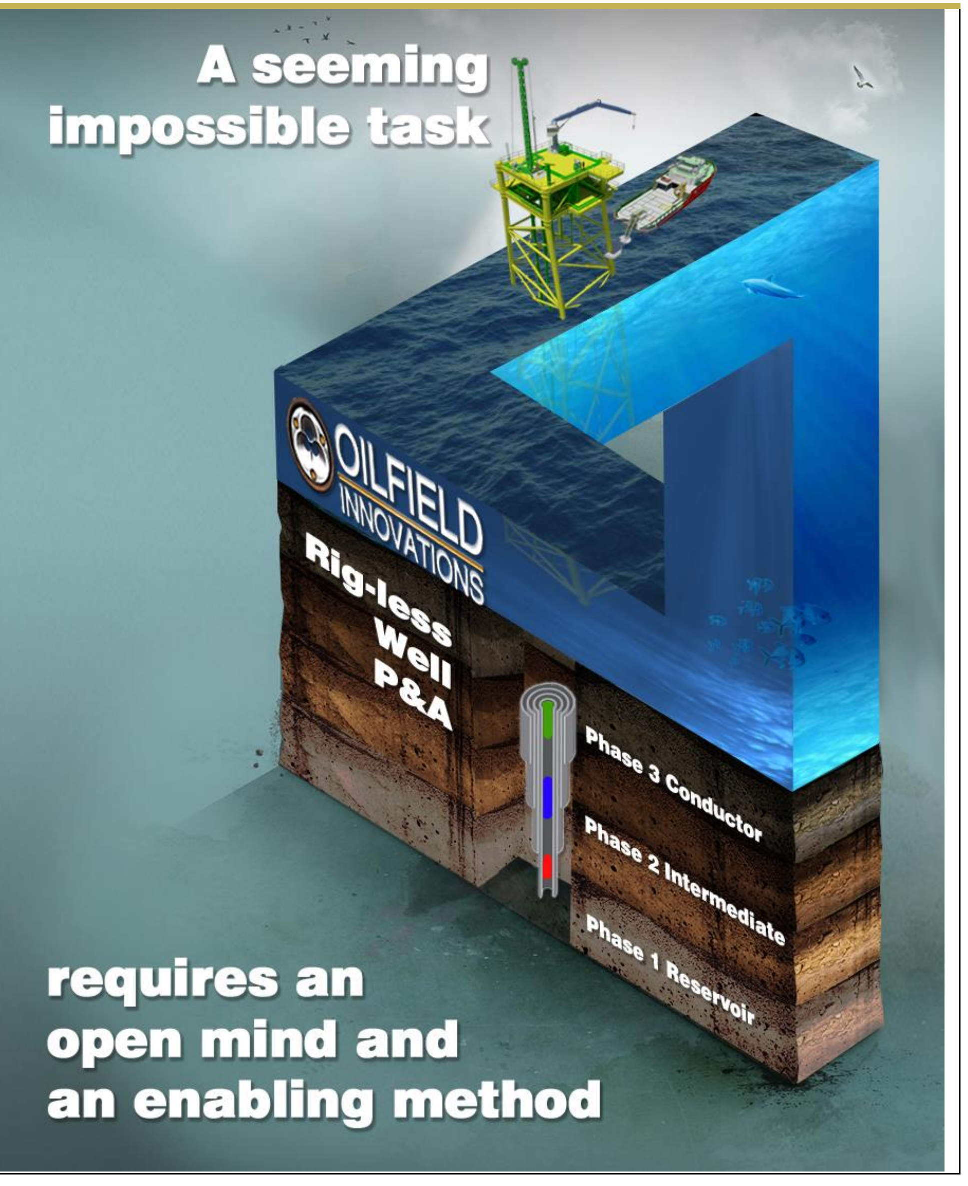
iii. Operators provide top level project manage and rely almost entirely upon service company experience for all well operations including well plug and abandonment.

iv. Operators are not equipped to develop new methods or new technologies and rely completely on the Service Sector as demonstrated by North Sea Oil and Gas Operators asking the UK Government to "*take control*" during the 23rd June 2016 UK Oil and Gas Authority brainstorming (hackathon) in Aberdeen Scotland.

v. Operators have fixed systems that cannot accommodate small companies providing innovative solutions, like the method in Section 7, and, therefore, continue to rely upon dominate service providers.

vi. The Section 7 method of reducing P&A cost by +/-50% can use "*all off-the-shelf Technology Readiness Level 7 (TRL-7) proven technology,*" but the method is being rejected by Operator personnel who are incompetent in slickline, wireline and/or coiled tubing.

vii. The cost of qualifying the Section 7 method of reducing P&A costs by +/-50% could be recovered within the first well plug and abandonment, but Operator personnel are too risk adverse to try it.



3. INTRODUCTION

This paper explores the root cause of high well plug and abandonment costs.

Oil and Gas UK, a trade association, separate well plug and abandonment into three phases comprising 1) plugging of the reservoir, 2) plugging of the intermediate portion of the well and 3) abandonment of the well conductor, wellhead and surface equipment (see Table 3).

Conventionally, fifty percent (50%) to eighty percent (80%) of offshore well plug and abandonment cost can be attributed to "*drilling rig support*" comprising heavy equipment and the support of a large workforce in an offshore environment.

Generally, in addition to drilling rig specific equipment… slickline, wireline and/or coiled tubing equipment are used from a drilling rig during Phase 1 plugging of the reservoir.

This analysis proposes possible mitigation measures comprising the continuation of slickline, wireline and/or coiled tubing usage into Phase 2 plugging of the well in order to mitigate the high cost of drilling rig support (see Sections 7, B.3.1, B.3.2, B.3.3, C.4.1 & C.4.2).

With regard to phase 3 well surface equipment abandonment, one possible mitigation measure is using jacking systems to replace drilling rigs so as to remove the need for a drilling rig completely (see Section E.5).

The use of slickline, wireline and coiled tubing is also applicable to subsea installations where jack-up crane support or light well intervention vessels (LWIV) can be positioned adjacent to or over subsea layouts.

Subsea wellheads can be removed in phase 3 of well abandonment using, for example, explosive severance.

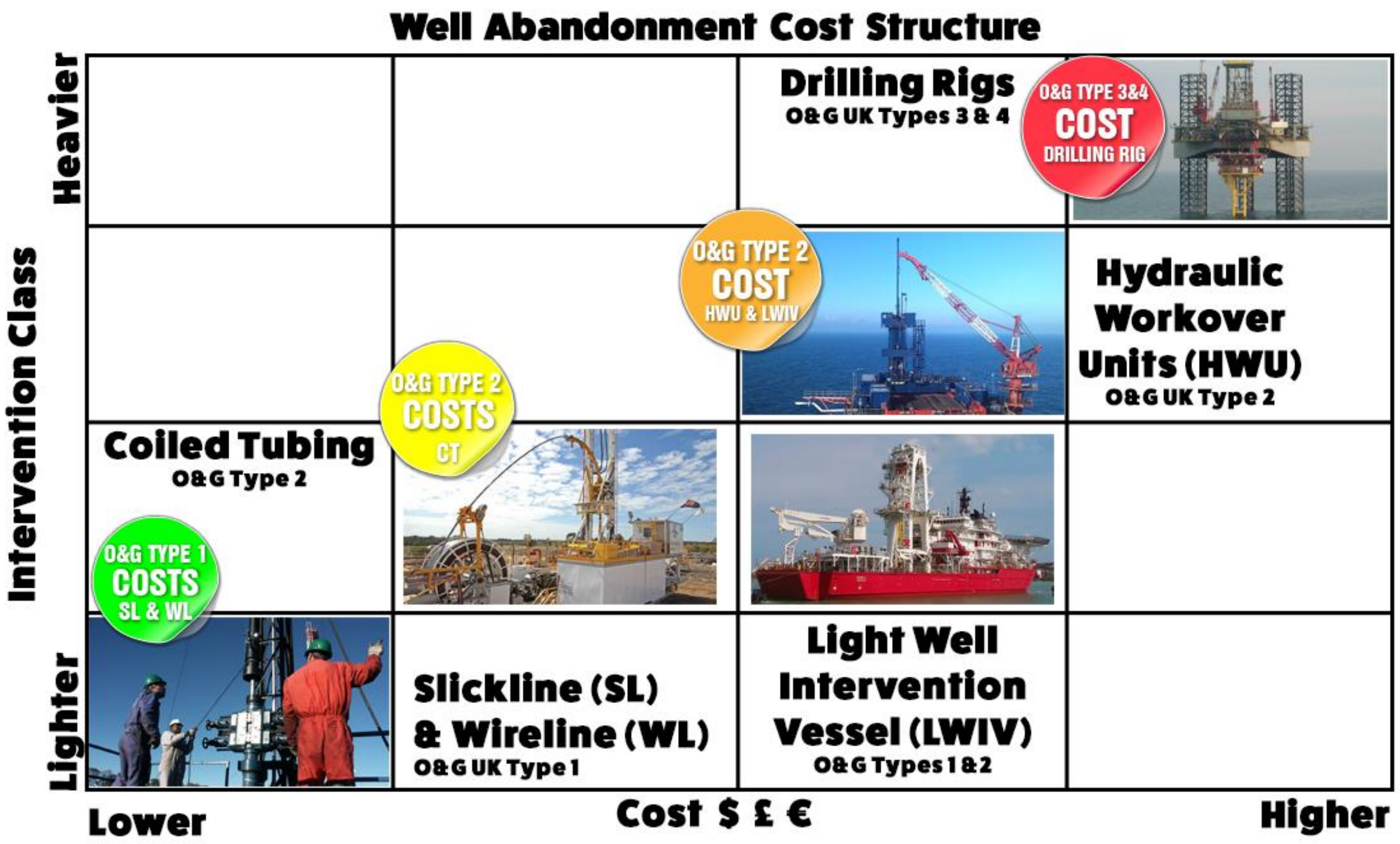
If the cost of mobile offshore drilling units and the cost of refurbishing drilling rigs on aging offshore platforms can be avoided, the cost of plug and abandonment can be reduced by orders of magnitude.

The complete removal of all drilling rig well plug and abandonment may not be possible, but it may be feasible to remove a drilling rig from 80% of well plug and abandonments.

4. WELL PLUG AND ABANDONMENT COMPLEXITY & COST STRUCTURE

Oil & Gas UK Complexity Types:

The Root Cause of Cost is a function of the complexity type.

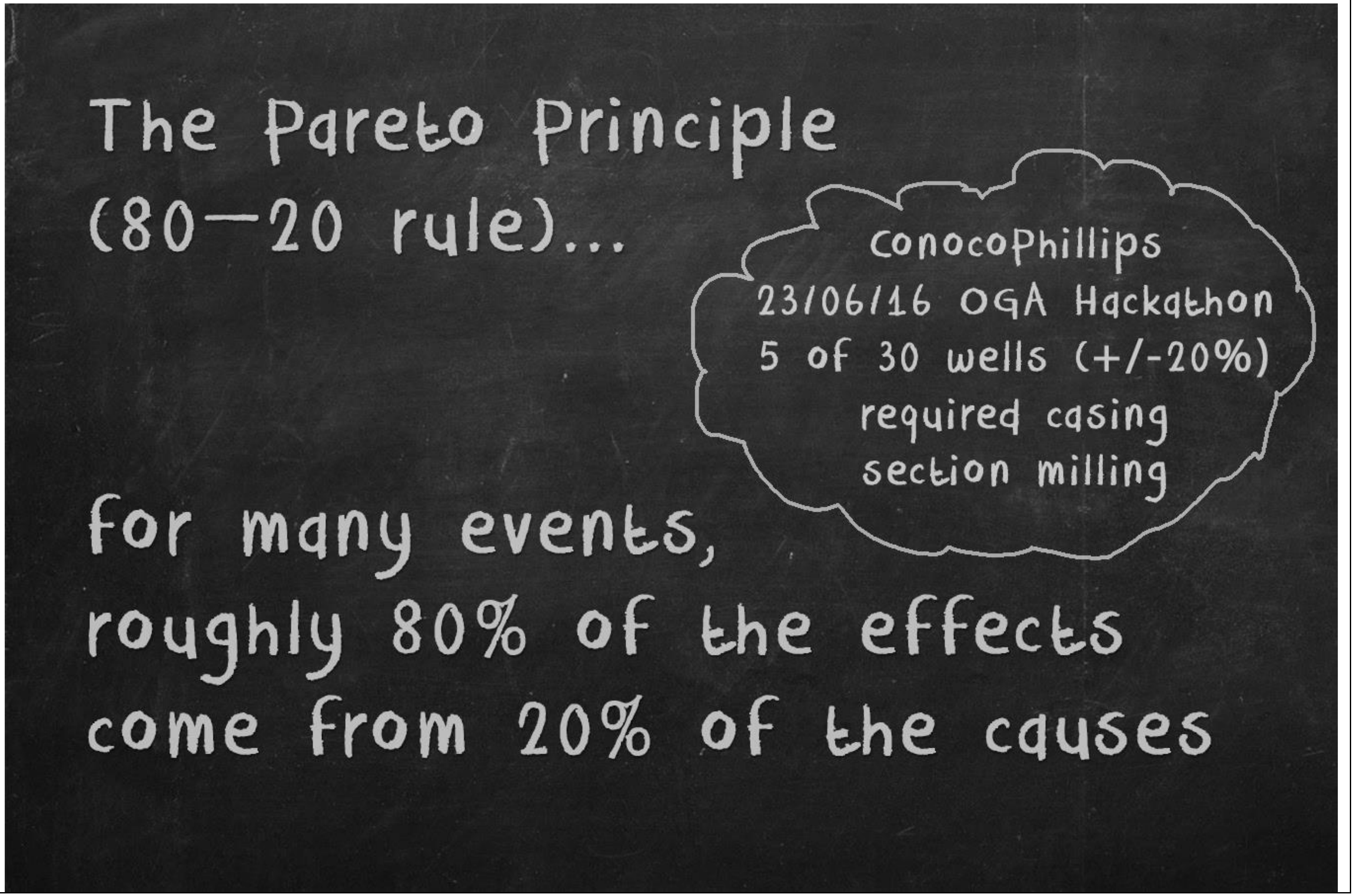


5. PARETO PRINCIPLE (80-20 RULE)

The root cause of high well plug and abandonment costs can be explained by the Pareto Principle or the 80-20 Rule.

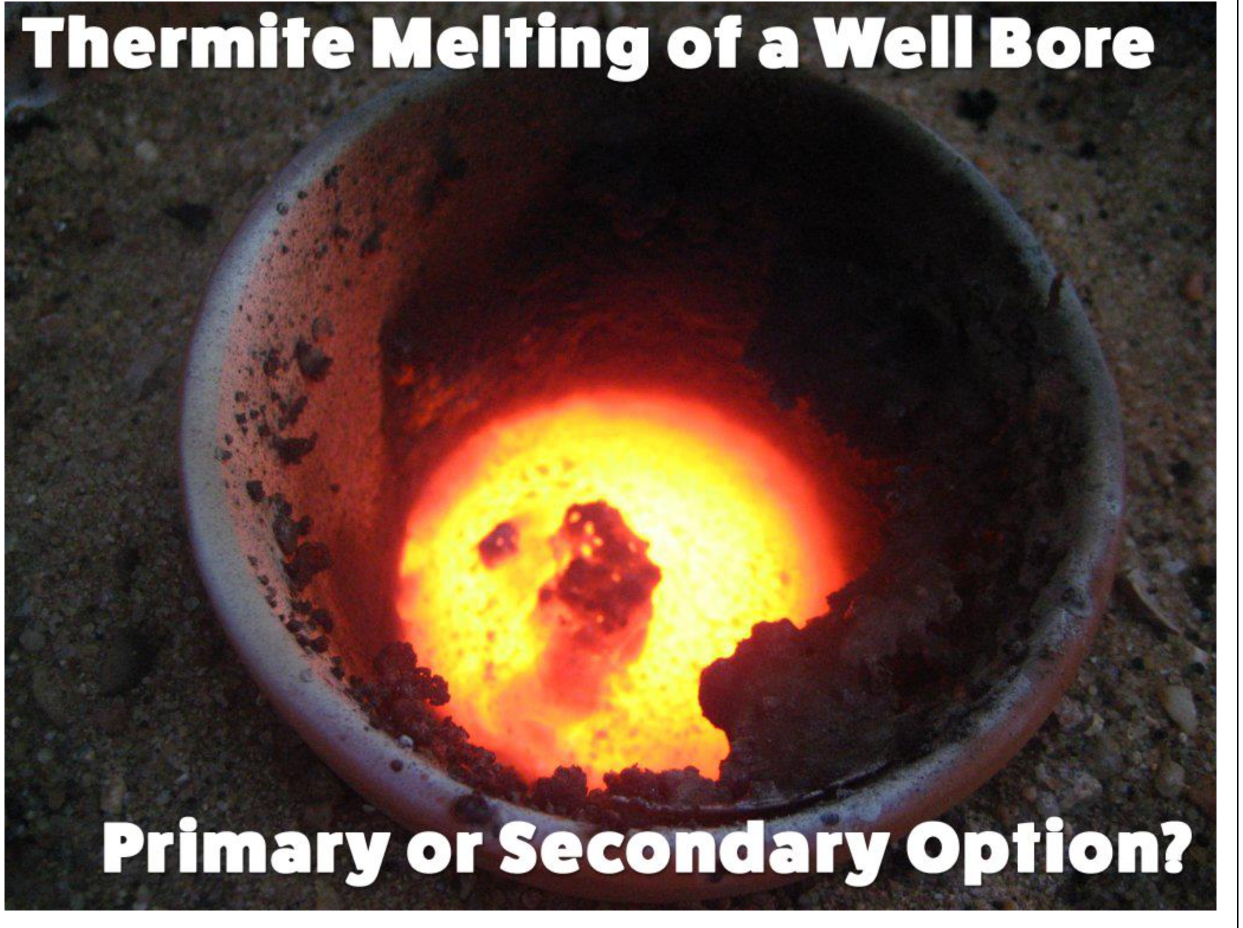
The high cost of well plug and abandonment can be attributed to having the resource costs for the worst 20% standing by for the 80% where they are not needed.

One possible mitigation is planning, plugging and abandoning the 80% with less resources standing by.



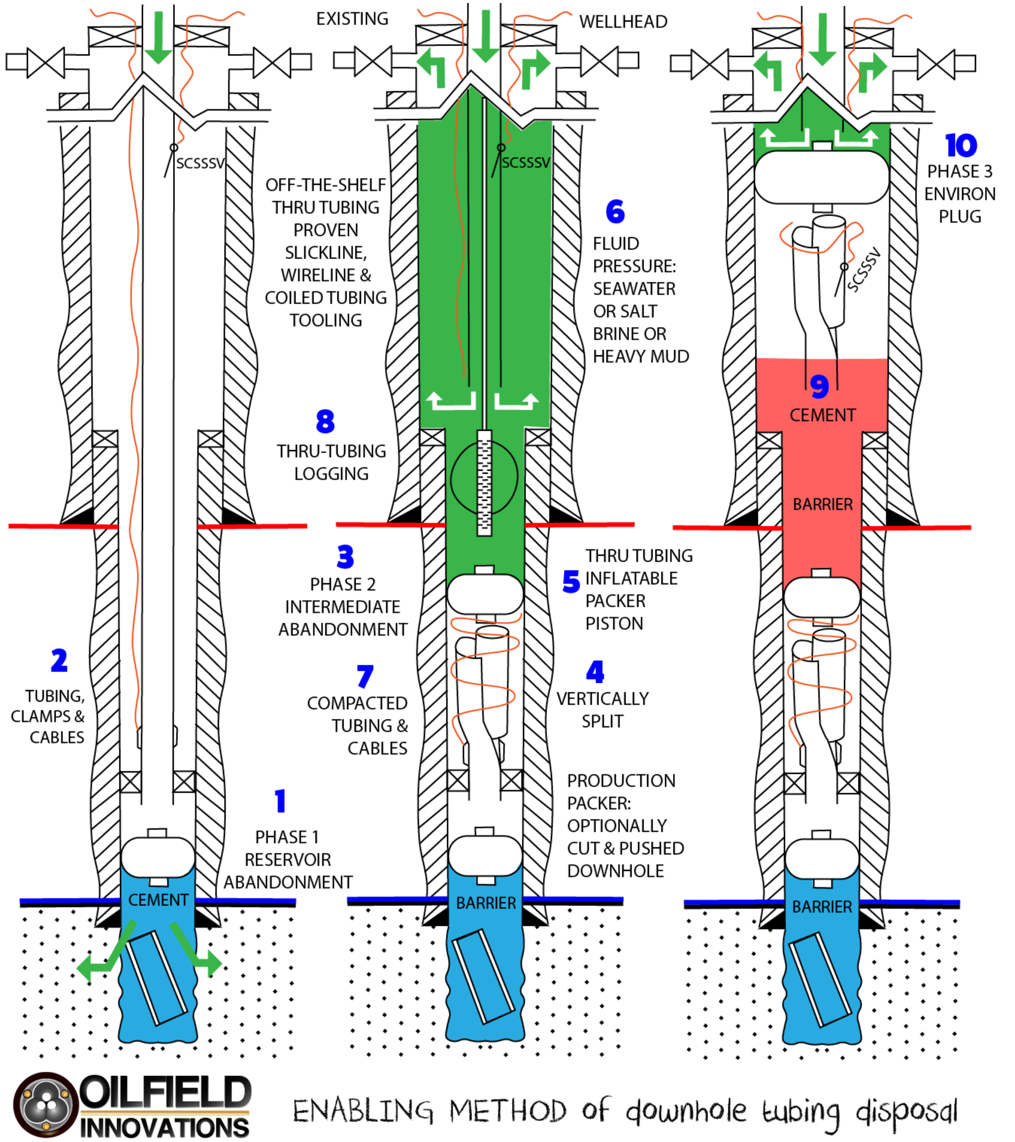
6. FIRST CHOICE OR LAST ALTERNATIVE?

- A slickline, wireline and/or coiled tubing enabling method (see Section 7) does not exclude other alternatives… it enables them.
- For example, if Centrica's trials are successful, and the cost, safety and environmental risks of using thermite to melt a well bore can be accepted…OILtd's enabling method can determine if the risks & costs of using thermite are necessary.
- Thermite can be a "*Secondary Option*" after the cement or alternate substances like salt or shale are logged to determine if costs and risks of thermite melting are actually needed.
- Using a slickline, wireline and/or coiled tubing enabling method (see Section 7) does not exclude thermite, casing section milling or any other alternative and provides information for choosing the most cost effective solution.
- Oilfield Innovations' enabling method (see Section 7) for through tubing logging of existing barriers can provide technical information to make an intelligent decision regarding whether thermite, explosives or electrical melting, a drilling rig or other methods are necessary.
- If other methods aren't necessarily, the well can be plugged and abandoned using our enabling method (see Section 7) to minimise risk and cost.



7. OILFIELD INNOVATIONS ENABLING METHOD OF WELL P&A

- An Enabling Method, using Slickline, Wireline and/or Coiled Tubing, is shown to the right.
- Slickline, wireline and/or coiled tubing are presently used on Drilling Rigs during Phase 1 Reservoir Abandonment (1) and can now be used in Phase 2 Intermediate abandonment (3) to compact tubing, cables and clamps (2), so as to avoid the need for a Drilling Rig.
- Phase 1 Reservoir Abandonment (1) can use present conventional methods or OILtd's enabling compaction method.
- In Phase 2 Intermediate Abandonment (3), the tubing can be split (4) and severed. A thru-tubing inflatable packer (5) can be expanded and pressured by fluid (6) pumped through the existing wellhead to drive the packer/piston and compact tubing, cables and clamps (7).
- Thru-Tubing Logging (8) can be used to verify cementation behind the casing. Allegedly, according to ConocoPhillips Station 2 Summary at the 23/06/16 UK OGA Hackathon, this is comparable to the "*Holy Grail*."
- After confirming well integrity, cement placement through the tubing can be used to form a barrier (9). See Sections B.4.1, B.3.1, B.3.2, B.3.3, C.4.1 and C.4.2 for cleaning and cementing options applicable to OILtd's enabling method shown to the right.
- Compaction and cementing can continue with the surface controlled sub-surface safety valve (SCSSSV) and control line disposed of downhole to provide an unobstructed plug.
- After the environmental cement plug is placed, Phase 3 well abandonment of the conductor and surface casings can be riglessly cut and removed by conventional pinning, jacking and cutting (10).



8. VERTICALLY CUTTING TUBING

CONVENTIONAL EXAMPLE:

Those who favour using a drilling rig often cast doubt upon vertically cutting when, in fact, it happens in many wells… albeit it is not conventionally desirable while production is ongoing.

As shown in the downhole camera pictures to the right, a number of wireline interventions within the well has worn a vertical track in the production tubing.

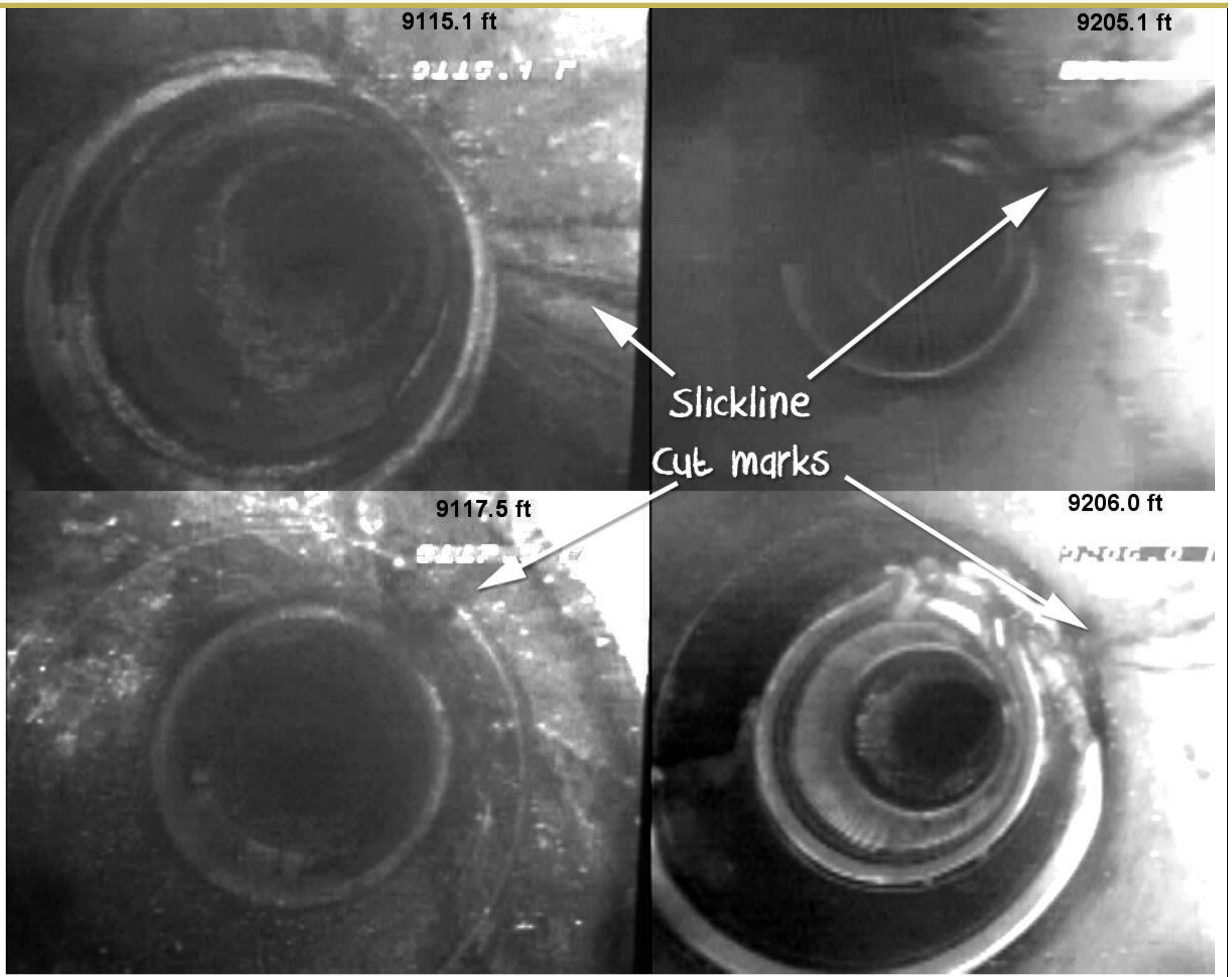
Regardless of the type of well intervention, it is not difficult to damage equipment in the well.

The difficult part of any intervention is "*not damaging*" the completion components.

Vertically slicing tubing. so as to allow downhole compaction, is not necessarily a difficult task.

ENABLING METHOD:

A slickline, wireline and/or coiled tubing enabling method (see Section 7 on the previous page) purposely cuts the tubing vertically to improve compaction of tubulars within the bottom portion of a well so as to provide a window for thru-tubing logging and placement of an unobstructed cement plug.



9. FAILING TO REDUCE COST BY DOING THE SAME THING OVER AND OVER AGAIN

Root Cause:

High well P&A costs can result from assigning the wrong skill set to the +/- 80% of the wells where a drilling rig may not be required and using a planning cycle with insufficient time to plan the use of anything other than a drilling rig, which results in failing to plan and, thus, planning to fail.

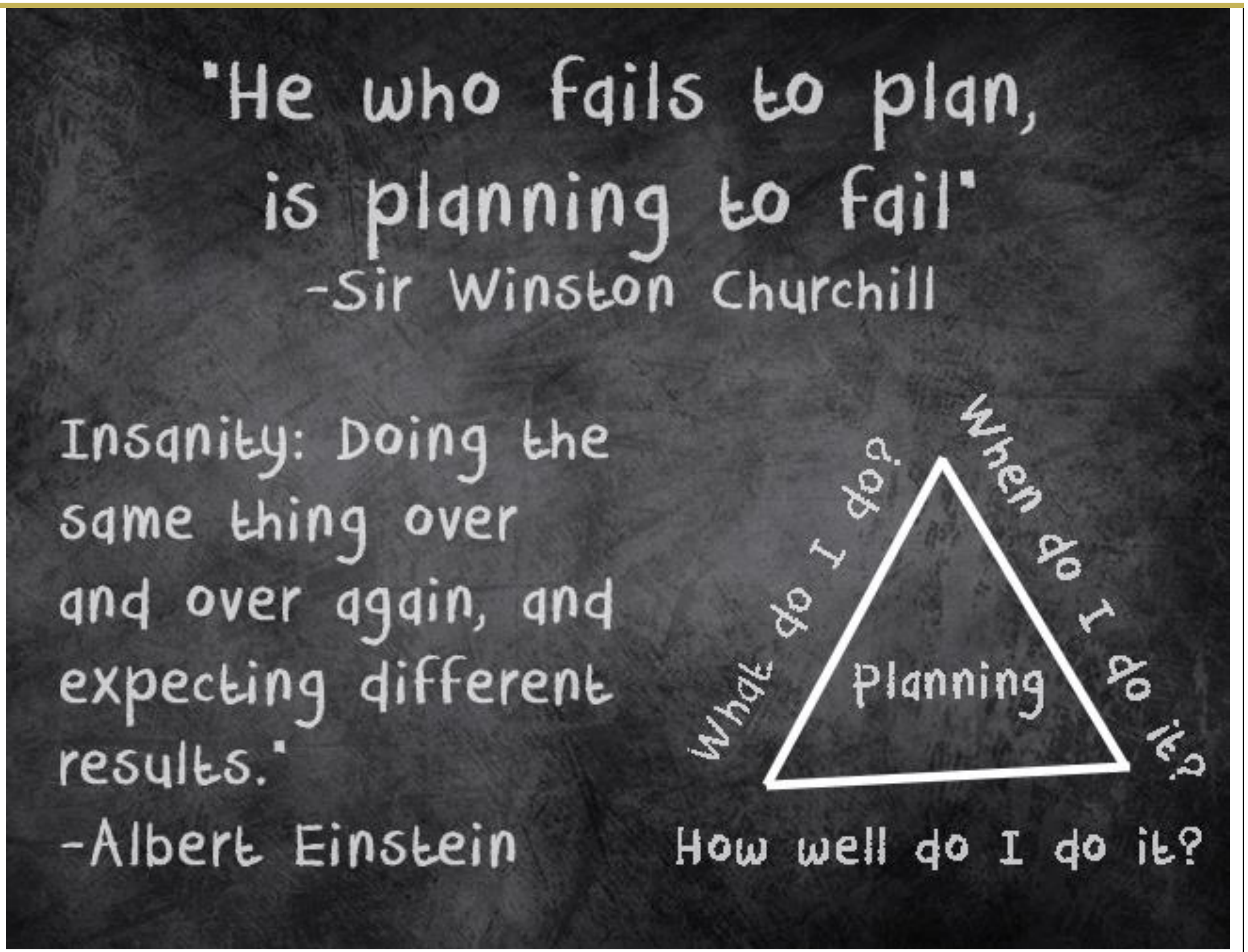
For example, at station 3 of the 23/06/16 OGA Hackathon, CononcoPhillips stated that their planning cycle was eight (8) months and, therefore, there was insufficient time to qualify new methods. Accordingly, doing the same thing over and over again is built into their planning cycle.

Failing to plan for the +/-80% that may not require a drilling rig is planning to fail to the reduce cost of well P&A.

Also, expecting cost reduction by doing the same drilling rig abandonments over and over again, may be insanity.

One Possible Mitigation:

Assign the P&A to people trained in thru-tubing operations and provide them sufficient time to plan to do something other than "*the way we have always done it.*" After they have abandoned 80% of the wells turn planning of the 20% over to drillers.



10. BOTH PLATFORM RIG REFURBISHMENT & MOBILE DRILLING RIGS ARE EXPENSIVE

Root Cause:

Normally manned installations with built in drilling rigs typically require refurbished just for well plug and abandonment and, hence, add significant cost that can be as expensive using a mobile offshore drilling unit (MODU).

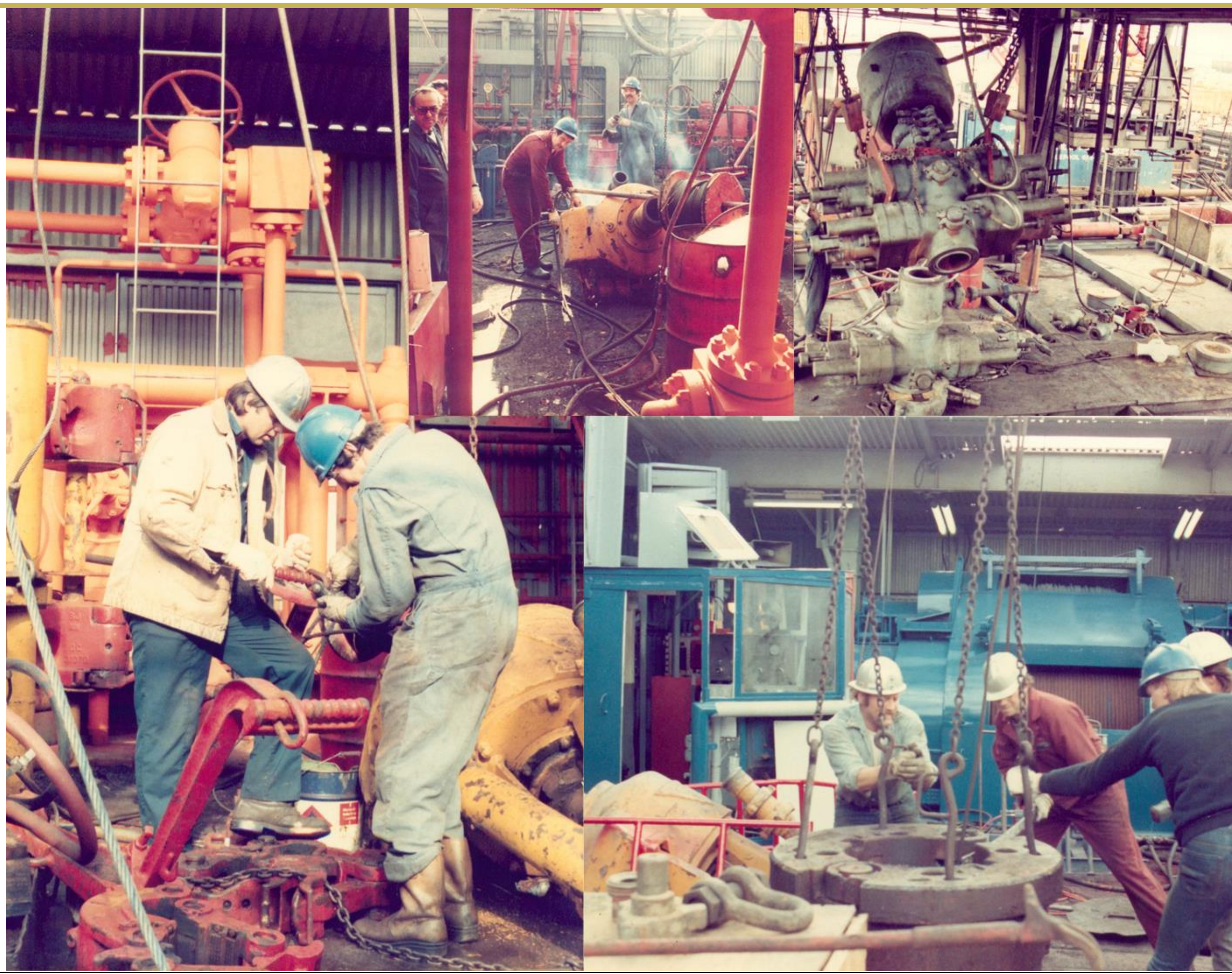
Possible Mitigation:

Do not refurbish a decrepit platform drilling rig or use mobile offshore drilling units (MODU).

Use OILtd's enabling method described in Section 7 to perform Phase 1 reservoir plugging and Phase 2 intermediate plugging, then use a jacking system, as described in Section E.5, for Phase 3 abandonment of the surface equipment.

If lacking or poor cementation exists use OILtd's enabling method described in Section C.4.1 and C.4.2 to plug the section.

If casing section milling is unavoidable for a small number of wells, use a hydraulic workover unit to mill the casings instead of investing a large sum of money in drilling rig refurbishment.



11. SAVINGS ASSOCIATED WITH PLANNING AND QUALIFYING NEW METHODS

Root Cause:

Short planning cycle with insufficient time and/or resources to qualify and use new methods of using proven tools or developing new tools.

Possible Mitigation:

Increase the planning cycle and allocate resources to qualify new methods, like OILtd's enabling method described in Section 7, so as to reduce offshore P&A costs significantly.

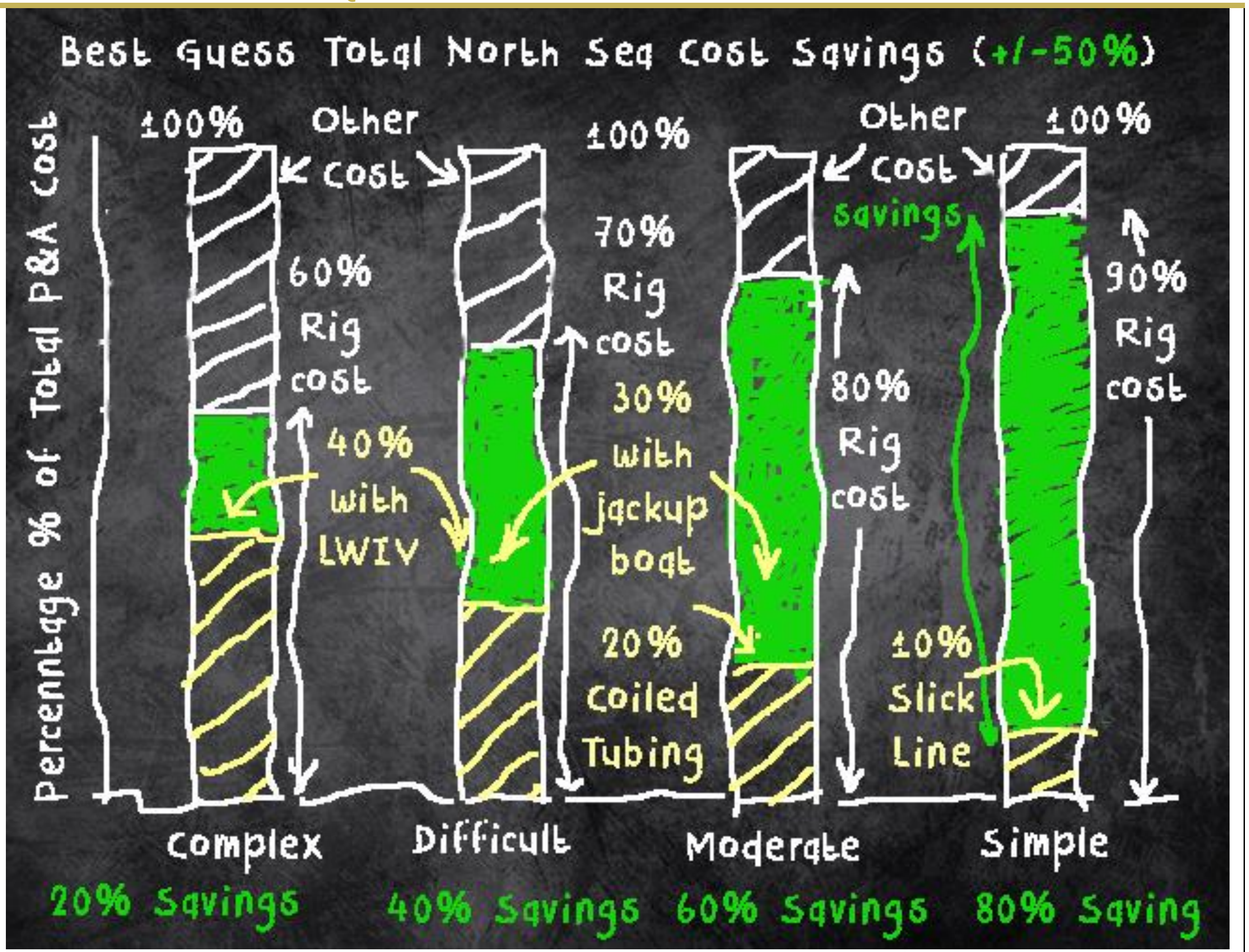
As shown on the right, the proportion of rig cost to total P&A costs varies according to complexity of the P&A. The easier the P&A the larger the proportion of rig cost to total cost.

If the well can be abandoned easily with a drilling rig it can be abandoned with slickline and wireline.

More complex wells may require coiled tubing, which can deliver significant savings from a manned installation.

If a jack-up boat or light well intervention vessel (LWIV) is needed the savings will be less.

When a large number of wells are considered, there is a possibility of saving 50% of the total P&A cost across the entire North Sea.



12. ROOT CAUSE SUMMARY

The root cause of high well plug and abandonment (P&A) costs can be attributed to:

A) People, Planning, Resources and Competencies,
B) Environmental Constraints above and below Seabed,
C) Material Volumes, Placement and Disposal Specification,
D) Method of Removing Downhole Completion Interference, and
E) Machinery Specification resulting in the selection of a Drilling Rig.

Contributing factors A) to E) are examined in more detail within Sections A) to E). Sections F) to H) describe the existing off-the-shelf tooling that can be used to reduce the cost of P&A.

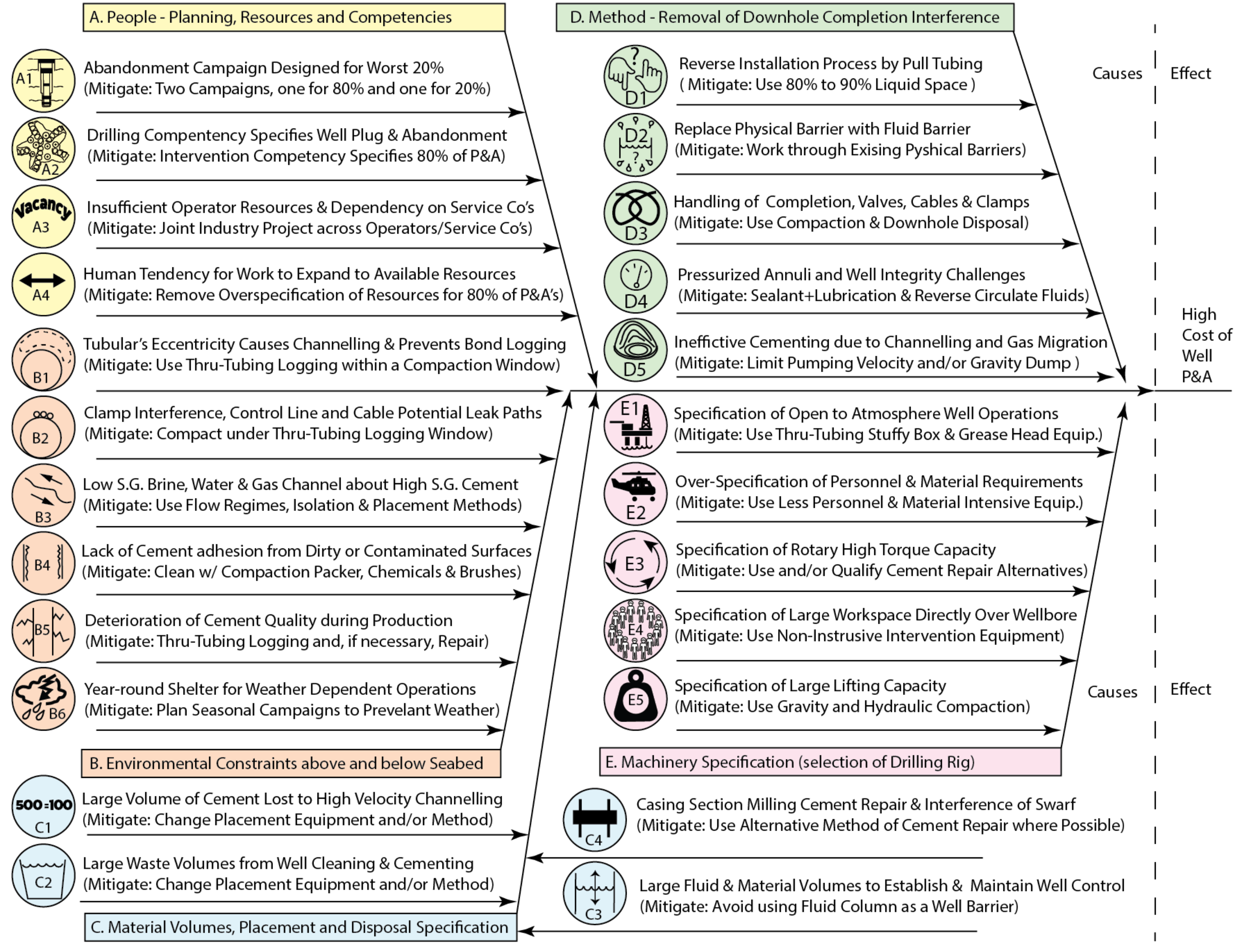
COST KEY:

Slickline/Wireline Costs

Coiled Tubing Costs

HWO & LWIV Costs

Drilling Rig Costs



A. ROOT CAUSES: PEOPLE – PLANNING, RESOURCES AND COMPETENCIES

O&G TYPE 3&4 COST DRILLING RIG

Root Causes:

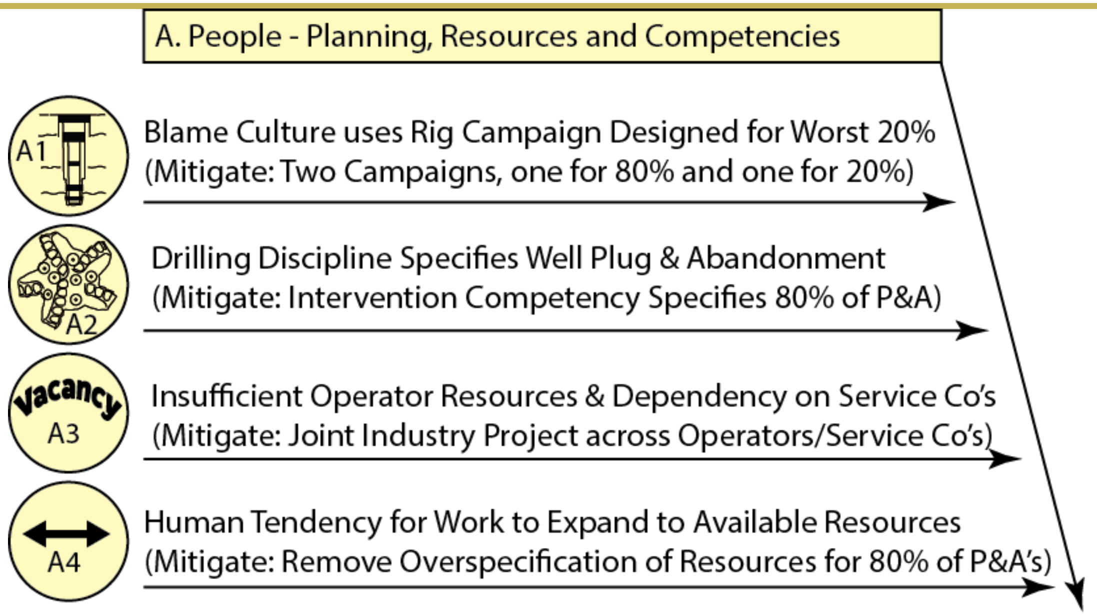
A blame culture associated with expenditures having no return on investment, combined with a short planning cycle and assignment of well abandonment to personnel who understand drilling rigs and not necessarily slickline, wireline and/or coiled tubing, causes selection of a drilling rig. A drilling rig may be needed for 20% of the worst cases where casing section milling is necessary. The other 80% that do not need casing section milling may not require the cost of a drilling rig.

Additionally, Operators have minimal well abandonment personnel and depend upon the resources of a drilling rig and service companies for competency, whereby drilling rig based work scopes are typically justified by comparing prices to the time cost of a drilling rig and, potentially, casing section milling may be carried out based on the perceived cost of other methods. For example, if cementation is perceived to be questionable, a drilling rig may skip cement bond logging and go straight to casing section milling without knowing that is was necessary.

O&G TYPE 1 COSTS SL & WL

Possible Mitigations:

Use a joint industry project (JIP) across operators and service companies to provide sufficient competency for two (2) campaigns comprising the use of an enabling method (see Section 7) of using limited rig-less resources to confirmation the 20% that require section milling and plugging the 80% that do not require drilling rig casing section milling prior to contracting a rig to abandon for the 20%.



CONTRIBUTING ROOT CAUSES OF HIGH WELL P&A COSTS

O&G TYPE 1 COSTS SL & WL thru tubing logging & plugging with O&G TYPE 2 COSTS CT and O&G TYPE 2 COST HWU & LWIV where necessary to plug and abandon +/-80% and, thus, leave +/- 20% requiring casing section milling with O&G TYPE 3&4 COST DRILLING RIG

A.1 Mitigation of Blame - Abandonment Campaigns Designed for Worst 20%

A1

O&G TYPE 3&4 COST DRILLING RIG

Root Cause:

Safety may be a "*no blame*" culture, but spending on well plug and abandonment has a distinct "*blame*" culture, since there is no return on investment and every penny spent is a penny too much.

Drilling engineers are limited to short planning cycle. For example, ConocoPhillips uses an eight (8) month cycle to plan 100% of their well plug and abandonments and, hence, plan for the worst 20%.

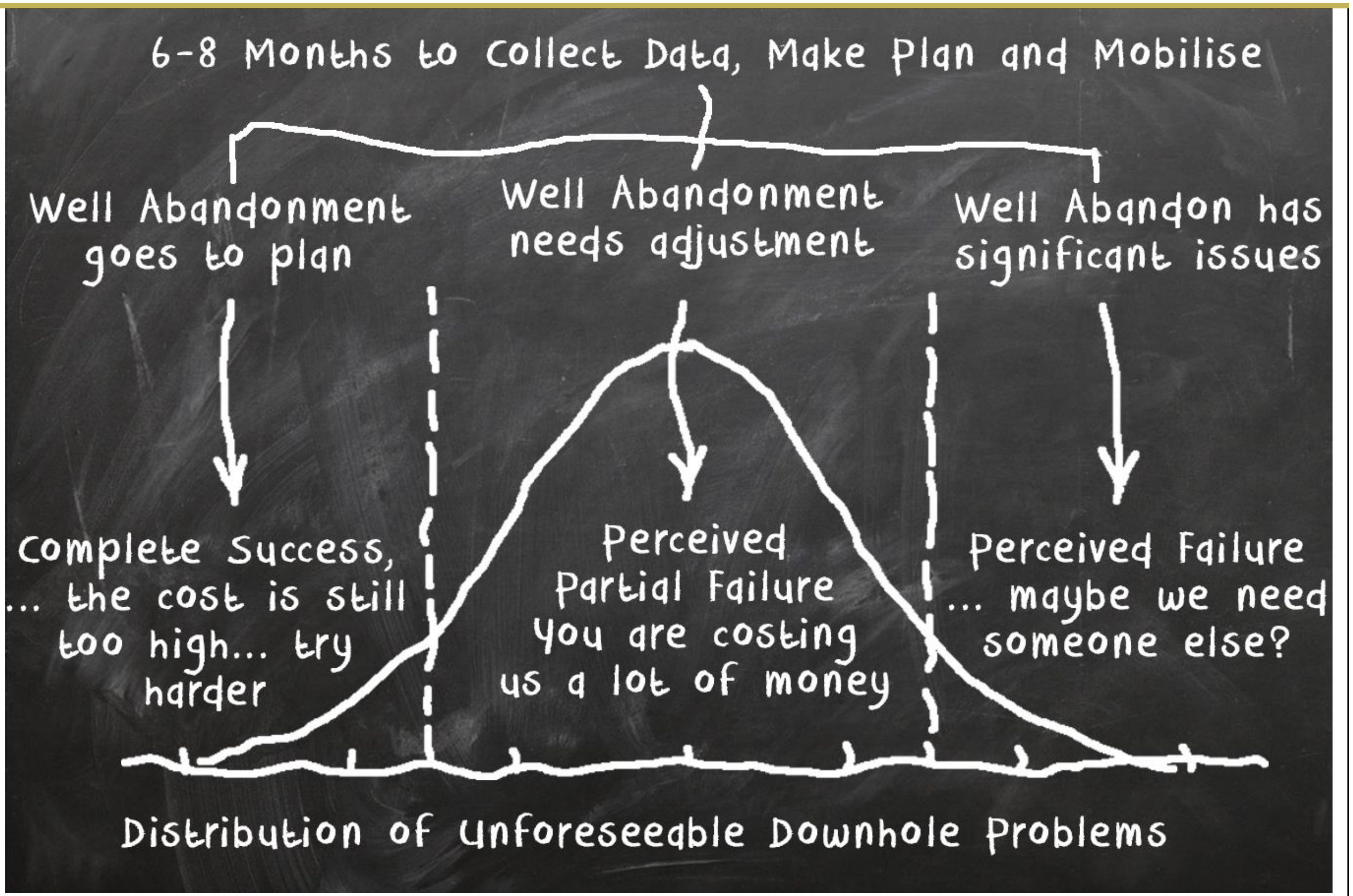
When ask to save cost, "*batch drilling rig abandonment*" is the typical mantra recited to management, but the benefits are limited to mob/demob savings offset by rig-up and rig-down costs.

Finally, when the inevitable non-productive time occurs, blame can be shared or placed across a large and complex work force associated with drilling rig operations.

O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

Increase the planning cycle time and accept that a lower cost enabling method (see Section 7) will not be able to plug and abandon all wells, but may be able to significantly reduce costs for +/-80% of the wells that it can plug and abandon.



While engineers close to retirement may be cross-trained, today's Oil and Gas Industry comprises specialist silos of expertise. Drilling Engineers are comfortable with using drilling rigs having 40-100 people of varying specialities to draw experience from and, generally speaking, may believe that slickline, wireline and/or coiled tubing crews of 4 to 10 people are higher risk because there is ten times less of an experience pool to draw from and/or they do not understand or are uncomfortable with pressure controlled thru-tubing operations.

A.2 Drilling Discipline Specifies Well Plug & Abandonment

Root Cause:

If you have ever met a "*Driller,*" it is hardly surprising that a "*Drilling Rig*" is a Driller's solution to every problem … for what is a Driller without a Drilling Rig?.

Drilling Rigs cannot effectively perform thru-tubing operations and, hence, well plug and abandonment work for a Drilling Rig always starts with "*pulling the tubing and completion.*"

When 60% to 90% of the cost of every well plug and abandonment, i.e. the cost of a drilling rig, is assumed to be an absolute certainty, the drilling rig itself becomes the root cause of high cost.

Possible Mitigation:

Use professionals trained in thru tubing operations like slickline, wireline and/or coiled tubing with an enabling method (see Section 7) to compact tubing into the 80% to 90% liquid space (see section B.1) within the casing.

Use a drilling rig or alternate rig-less method only after OILtd's enabling method thru tubing logging (see Section 7) confirms a drilling rig, or an alternative rig-less method, is needed for proper plug and abandonment of the well (see Section B.1.1).

A.3 Insufficient Operator Resources & Dependency on Service Companies

Root Cause:

An Operators' competency comprises finding and producing hydrocarbons.

Operators do not keep large groups competent in drilling and well abandonment. Operator's Drilling Staff project manage drilling contractors and service companies who have the experience and competency in drilling and well abandonment.

It is hardly surprising that contractors that profit from use of drilling rigs and methods justified based upon the hourly time cost of a drilling rig continue to recommend "*doing the same thing that they have always done.*"

One Possible Mitigation:

Use a joint industry project (JIP) of Operators, Government and a "*menu*" of competing Service Companies qualified in various areas of abandonment that can be used to avoid the cost associated with a drilling rig.

Service providers could join the JIP so as to establish frame agreements and gain information and JIP controlled patent rights to develop lower cost options.

Operator and Government could use and spread work across contractors to facilitate performance measurement, promote competition and, thus, keep costs competitively low.

Operator's have a Small Group to Coordinate Activities

Technical Expertise Outsourced to the Service Company

A.4 Human Tendency for Work to Expand to the Available Resources

Scope A4 — O&G TYPE 3&4 COST DRILLING RIG

Root Cause:

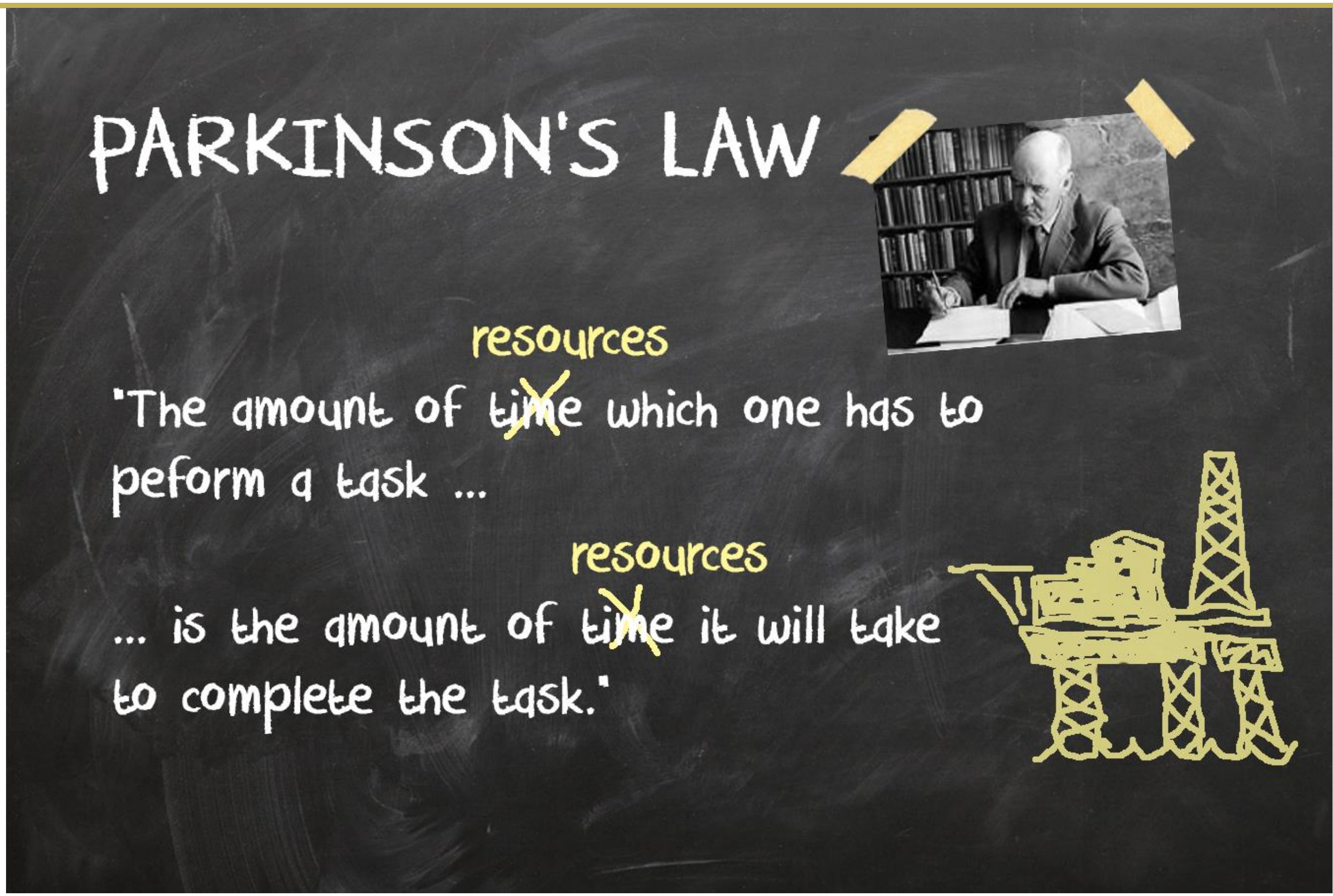
If you have the resources of a drilling rig and a large crew trained in drilling rig operations at your disposal, recommendations from the field will involve drilling rig solutions, whereby always performing drilling solutions further justifies the subsequent selection of future drilling rig P&A.

It is a win-win-win situation for the drilling contractor, and service companies justifying the cost of the solutions based upon the time cost of a drilling rig, as well as the drilling engineers trained in the use of, and who are comfortable with, the using of a drilling rig. Unfortunately, it is a lose-lose situation for Operators and Government who pay significantly more than is necessary.

O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

Limit the available resources to thru tubing logging using OILtd's enabling method (see Section 7) until the actual resource requirements can be determined.



B. ENVIRONMENTAL CONSTRAINTS ABOVE AND BELOW SEABED

Root Cause:

The constraints used to justify the use of a drilling rig are real and valid; however other methods, for example OILtd's enabling method in Section 7, can also satisfy the same constraints.

Lower cost proven wireline methods and equipment pre-date the advent of rotary drilling rigs and, hence, have a proven track record of success.

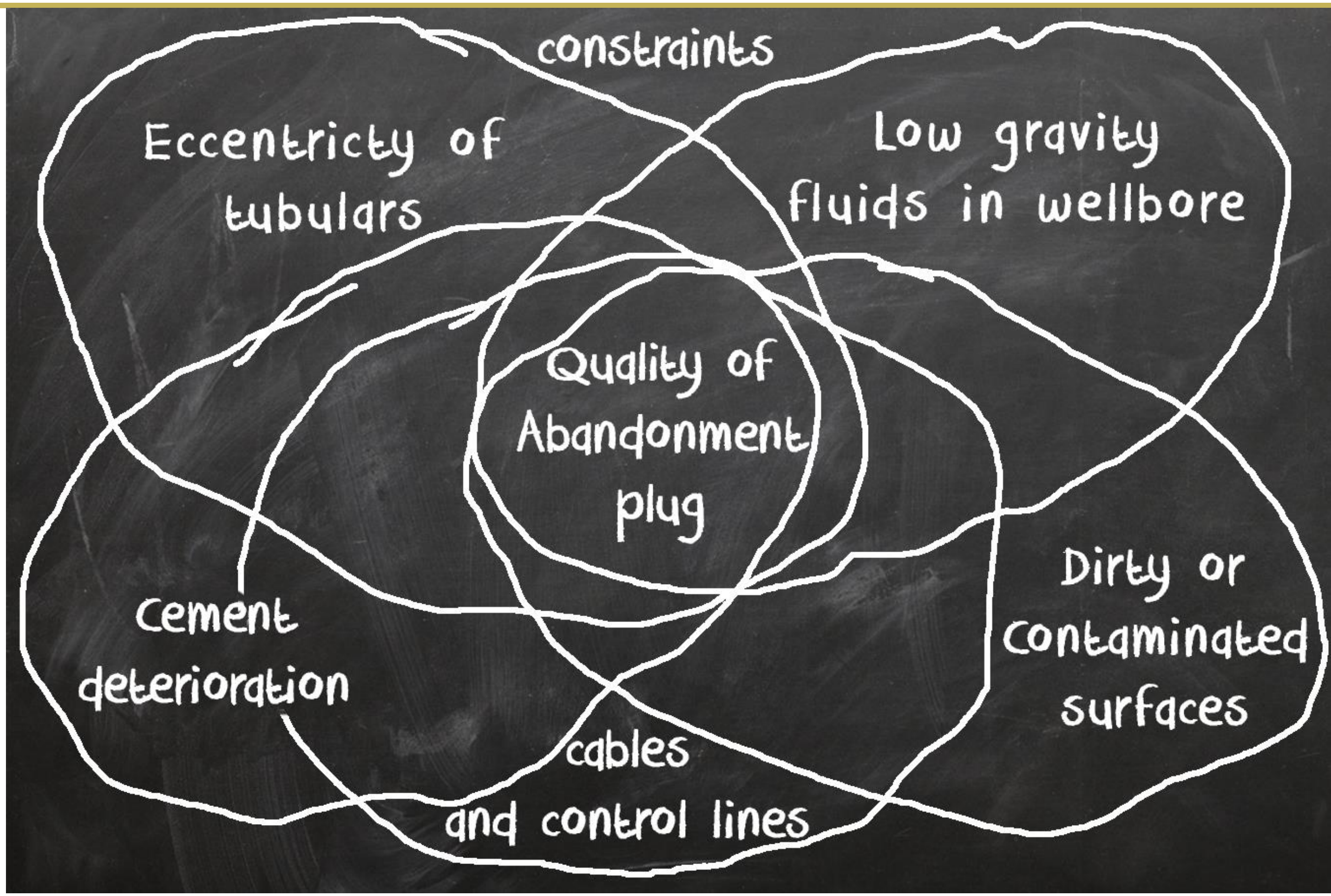
Before the advent of rotary drilling, wireline has been used to drill wells since around 400 AD.

Rotary Drilling Rigs are designed to improve "the rate of drilling," but they are not designed for thru-tubing operations.

The root cause of high well plug and abandonment costs can, therefore, be traced to how "*rotary*" drilling rigs manage the constraints shown to the right.

Possible Mitigation:

Satisfy the real constraints shown to the right, using a lower cost method, see Section 7, that enables the use of other low cost off-the-shelf equipment, but does not prevent the later selection of a drilling rig in instances where no other method can be justified.



B.1 Tubular's Eccentricity Causes Channelling and Prevents Thru-Tubing Cement Bond Logging

Root Cause:

As further discussed in Section B.1.2, eccentricity prevents thru-tubing bond logging of the cement or rock (e.g. shale or salt) bond or seal around the casing.

As discussed in Sections C.1, C.2 and D.5, eccentricity of one tubular within another causes fluid frictional associated with channelling of pumped high velocity fluids used in cleaning and cementing.

Generally speaking one tubular's eccentricity within another must be removed or it will prevent thru-tubular logging and require large volumes of high velocity fluids to be pumped during cleaning and cementing.

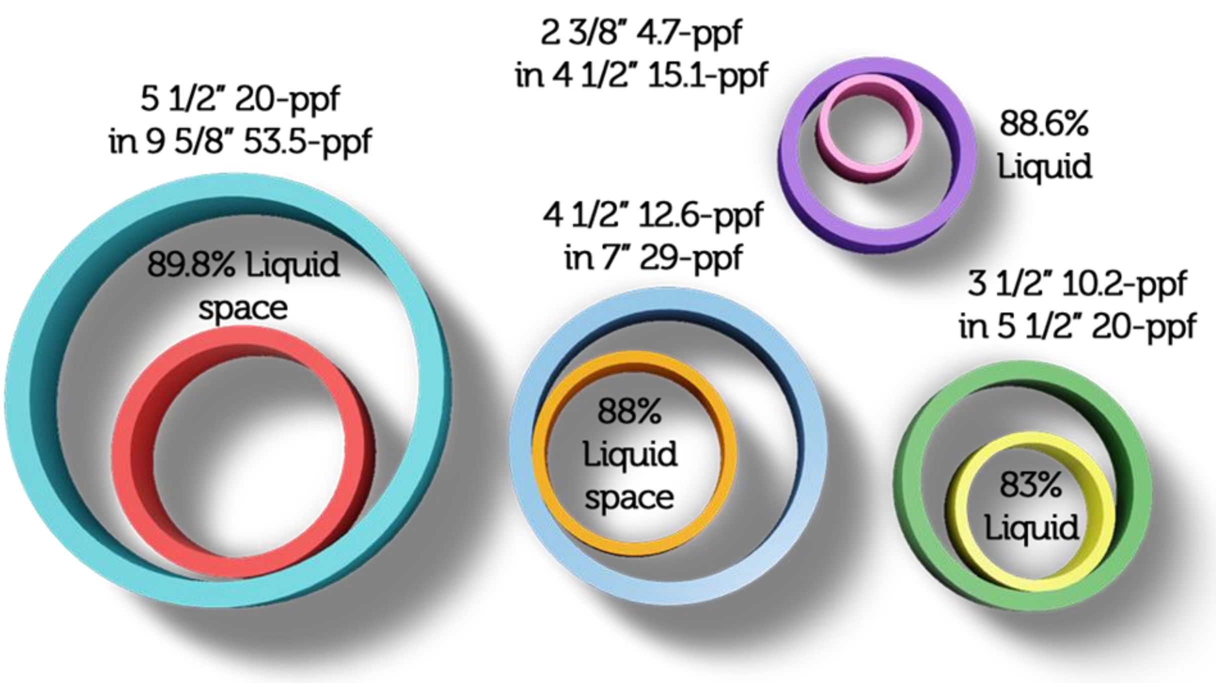
Pulling tubulars is the primary technical justification for using a drilling rig and, hence, the primary root cause of high plug and abandonment costs because drilling rigs comprise the highest cost component of well plug and abandonment.

Possible Mitigations:

Instead of viewing space and eccentricity as a problem justifying the use of a drilling rig, view well design and eccentricity as an opportunity to lower the cost of well plug and abandonment.

All well designs have 80% to 90% liquid space with eccentric tubulars that facilitate compacting tubulars side by side to provide space for logging and unobstructed cleaning and cementing using OILtd's enabling method in Section 7.

Use OILtd's enabling method, liquid space and eccentricity as assets for lowering well plug and abandonment costs.



B.1.1 Qualifications For Placing A Good Cement Plug

Root Cause:

Compliance with "*best*" or "*good*" industry practice for replacing cap rock is a root cause of high well abandonment costs, albeit it is a root cause that is absolutely necessary.

"*Tubing eccentricity,*" as a root cause of high cost, is supported by the removal of the tubing and stand-off recommendations from the 2012 Oil and Gas UK (O&G UK) Illustration of the "*Best Practice*" schematic, shown to the upper right, from the 2015 O&G UK "*Good Practices*" guidance, shown to the lower right.

Arguably, a perceived legal liability loop hole, associated with avoiding the technical realities of eccentricity, may have been intended when using the word "tubulars" in 2015 guidance instead of the words "tubing" and "casing" used in 2012 guidance.

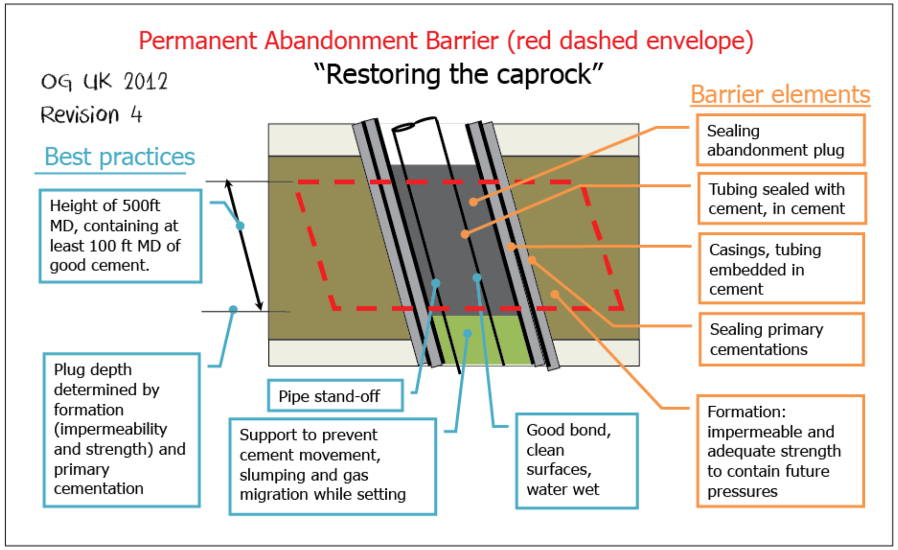
During the 23rd of June 2013 Oil and Gas Hackathon in Aberdeen, for the purposes of cost reduction, the ability to violate the "*minimum*" requirements of a "*restoring caprock,*" shown to the right, was raised on a number of occasions.

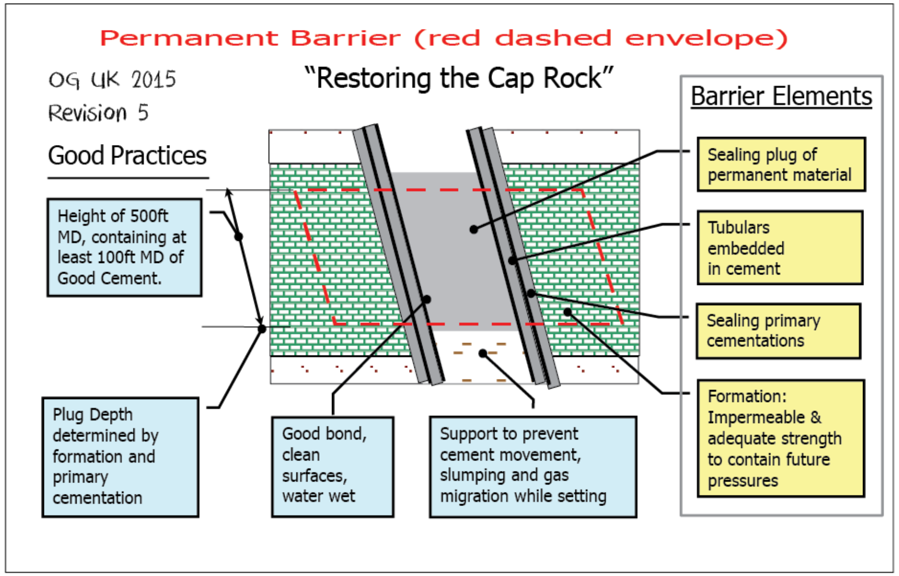
Obviously, common sense must prevail and a resounding "*NO*" must be voiced to anyone who proposes that a government of the people should allow companies to break the foundational rules of "*best*" or "*good*" practice.

The potential catastrophic consequences, and nearly Piper Alpha severity, of the UK Elgin Franklin G4 Well Abandonment Incident (shown to left) must be considered when violating the "*minimum*" plug and abandonment requires.

One Possible Mitigation:

Meet the "*minimum*" O&G specification for "*replacing caprock*" using OILtd's enabling method described in Section 7 and, where necessary, use the associated enabling method variations described herein.





B.1.2 Eccentricity and Thru-Tubing Cement Bond Logging

B1

Root Cause:

At the 23rd of June 2016 Hackathon, during the Station 2 summary, ConocoPhillips referred to thru-tubing logging as the "*Holy Grail*" of well abandonment.

Obviously, ConocoPhillips refers to deciphering the cryptic response caused by eccentric tubing within casing. Various other Operators are also exploring eccentric thru-tubing logging technology

For example, as presented in the 15 June 2016 SPE well abandonment conference, and mentioned it in the OGA Hackathon, Statoil have used a drilling rig to lift tubulars so as to enable thru-tubing logging.

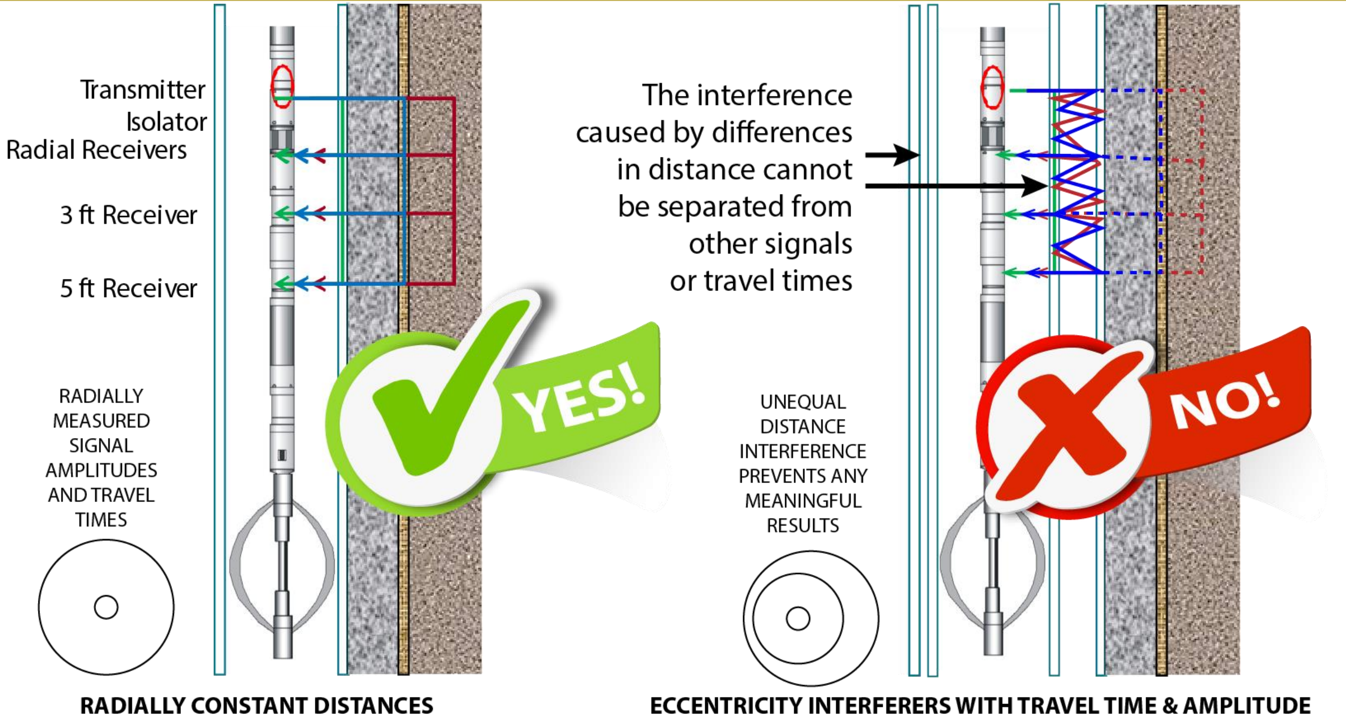
Obviously, given that the "*simple*" method of lifting the tubing, or using OILtd's enabling method described in Section 7, already exist, the root cause of high well plug and abandonment costs may be a "*human desire for a more complex solution*" to thru-tubing logging since simple thru-tubing logging methods already exist.

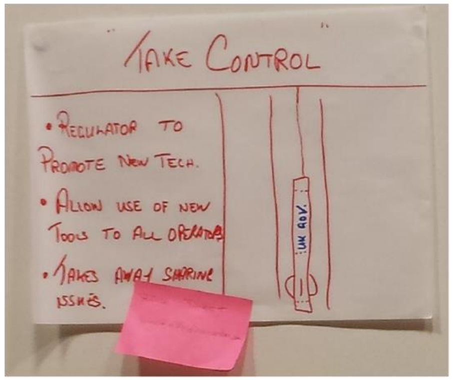
O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

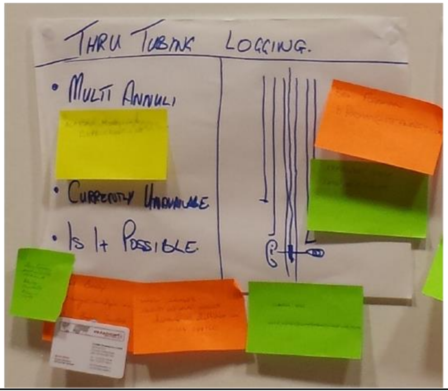
OILtd's enabling method shown in Sections 7, B.3.1, B.3.2 and B.3.3 can be accomplished with off-the-shelf equipment to provide low cost thru-tubing logging during well plug and abandonment.

Thru-tubing logging can be used to determine, plan for and execute the lowest cost method of well plug and abandonment.





Aberdeen Scotland Brainstorming June 23, 2016, appearently, some believe that Thru-Tubing Logging is the "Holy Grail" and want UK Government Control or, more likely, Government Assistance



B.1.3 Phase 2 Well Plugging is the Missing Link to Cost Reduction

O&G TYPE 1 COSTS SL & WL

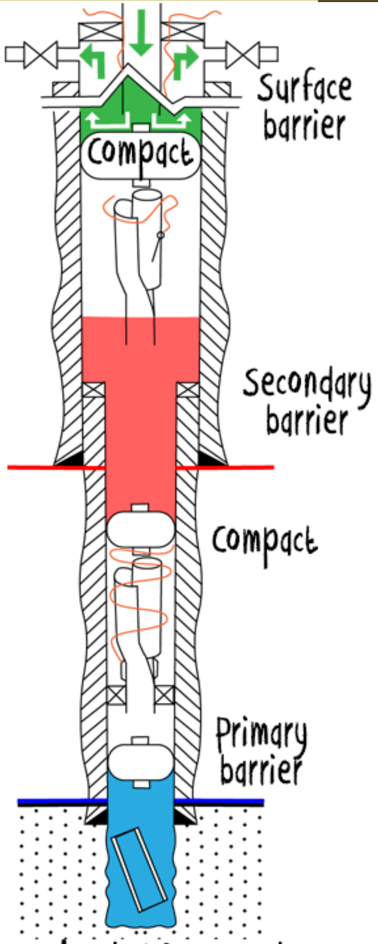
Phase 2 Well P&A Mitigation:

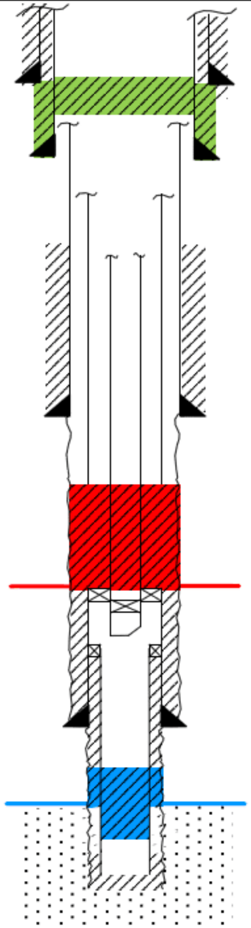
Phase 1 well abandonment using drilling rig specific equipment is presently not cost effective and, despite having a drilling rig available, typically pressure controlled slickline, wireline and/or coiled tubing are presently deployed from a drilling rig acting as an accommodation vessel to perform Phase 1 reservoir abandonments.

Accordingly, because a jacking system can be used for Phase 3 surface equipment abandonment of a well, see Section E.5, the question of high well P&A costs becomes whether, or not, phase 2 intermediate well abandonment can be accomplished riglessly to avoid the cost of using of a drilling rig altogether.

Oil and Gas UK provide various diagrams which are, more or less, equivalent to the NORSOK diagram, shown to the far right, describing the overall process of well plug and abandonment.

Comparing OILtd's enabling method described in Section 7 (left side of illustration to the right) to the NORSOK requirements (right side of same depiction) shows that a rig-less means can be used to meet North Sea guidelines and standards of Phase 2 well plug and abandonment.





Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Liner cement	22	
Casing	2	
Cement plug	24	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing cement (between casing and tubing)	22	
Cement plug*	24	
Open hole to surface well barrier		
Casing cement	22	
Casing	2	
Cement plug	24	

*Inside tubing.

NORSOK D-010
Rev. 4, June 2013

Figure 9.6.5.3 – Permanent abandonment, perforated well, tubing left in hole

Note: Phase 3 surface equipment plug and abandonment, depicted in green, can be accomplished with off-the-shelf tooling for both platform and subsea wells using, for example, perforating and squeezing of cement followed by abrasive or explosive severance and jacking or lifting of the wellhead.

B.2 Clamp Interference, Control Line and Cable Potential Leak Paths

Root Cause:

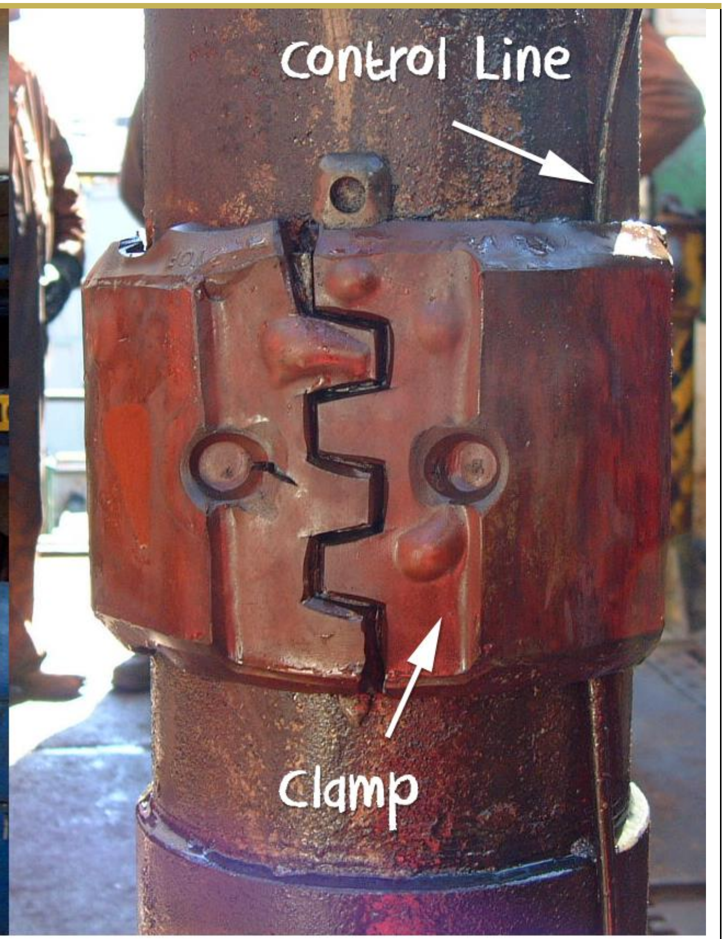
Tubing Eccentricity (see Section B.1) is a root cause of high well costs that is often compounded by, or replaced by, clamp and control line and cable interference that inhibits cementation and can cause leak paths that further cause well P&A integrity issues (see Section D.4).

One of the many root cause factors against cementing around tubulars within tubulars are the presence of control lines (shown to the right) that can cause leak paths and, hence, should be removed.

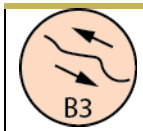
The presence of control lines is one of the real issues used to justify pulling the tubing with a drilling rig for well plug and abandonment and, thus, is an associated root cause of high plug and abandonment costs.

Possible Mitigation:

Use OILtd's enabling method described in Section 7 to compact control lines and clamps into the liquid space of the well (see Section B.1) and, thus, provide the same unobstructed space offered by a drilling rig without incurring the associated high cost.



B.3 Low Specific Gravity Brine, Water and Gas Channelling about High Specific Gravity Cement



Root Cause:

When high specific gravity (sg), or "*heavy*," fluid is placed upon lower sg, or "*lighter*" fluid, gravity pulls the heavier fluid through the lighter fluid as shown to the right, which can be an issue when lighter fluid is used to support heavier cement as shown in O&G UK guidelines (see Section B.1.1).

Lighter "*viscous*" fluids can be used to support heavier cement, however, ineffective placement of the viscous fluid and/or gas migration (see Section D.5) remain serious issues that can remove viscous fluid support.

In an effort to save time and cost, drilling rig plug and abandonments often omit setting of a mechanical bridge plug, which can allow cement to fall through lighter fluids and/or allow gas migration upward to contaminate cement.

Typically drilling rigs will pump a viscous fluid then lift the pipe string and place cement. They will then wait for the cement to set before tagging the cement to see if it has fallen through the viscous fluid. Many times the tag is not successful and drilling rigs end up making numerous repeat attempts because, after the first attempt, it is unlikely that a bridge plug can be run due to residual cement. Viscous fluid then becomes the only remaining support means.

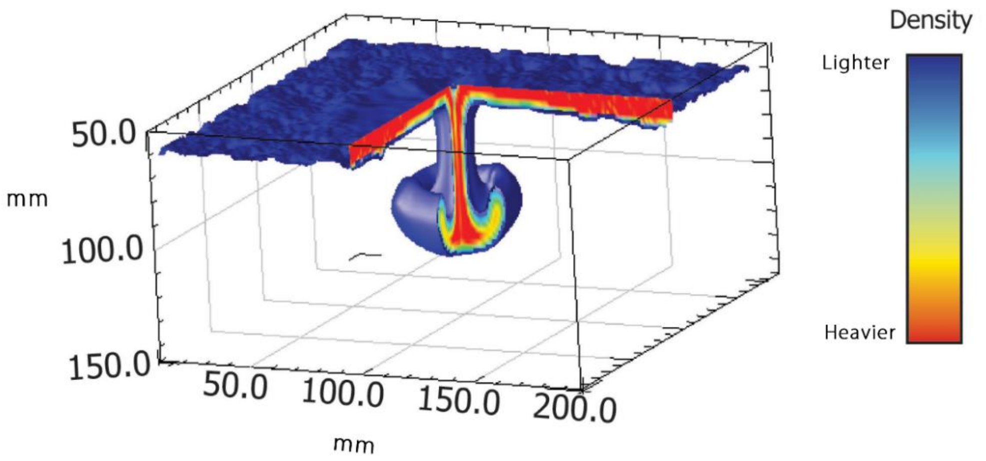
Accordingly, low specific gravity fluids and gas channelling can cause inefficiencies that lead to well integrity issues (see Section D.4) and, hence, are root causes of high well plugging costs.

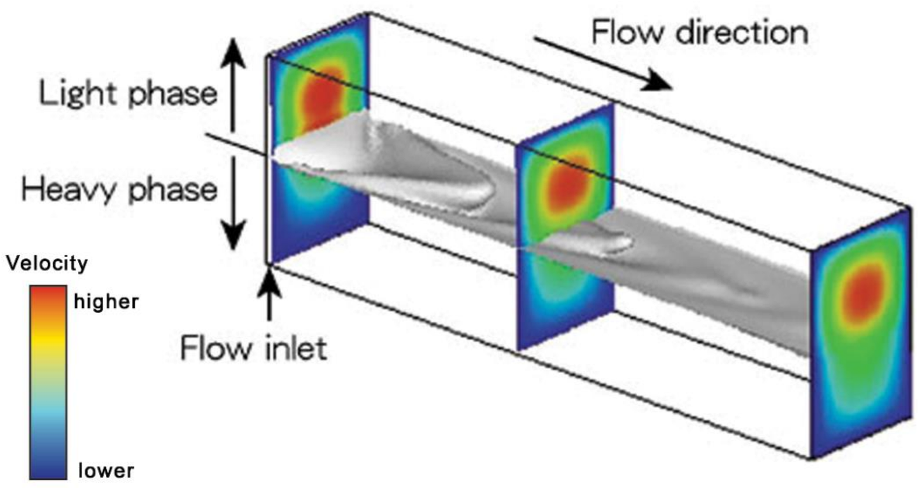
Possible Mitigations:

As shown on the right side of Section B.3.1, use the natural channelling of high specific gravity cements through lighter fluids to place cement through the fluids onto the compaction piston used in OILtd's enabling method described in Section 7.

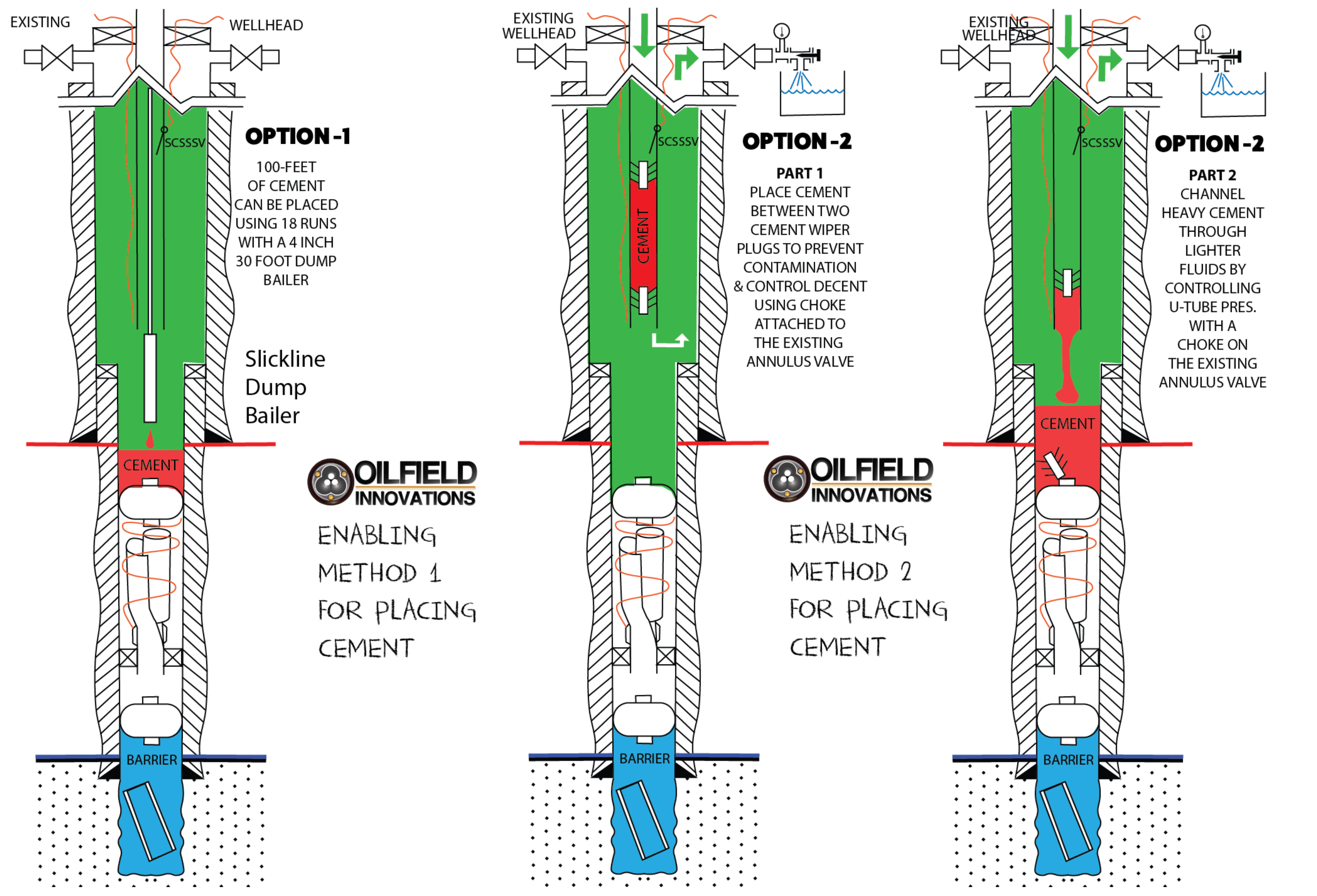
Alternatively, as shown on the left side of Section B.3.1, use a wireline dump bailer to physically place cement onto the compaction piston used in OILtd's enabling method described in Section 7.

Other possible methods of using a telescopic stinger are illustrated in Section B.3.2, while a further method of cement bond logging after cementing with the stinger is shown in Section B.3.3.



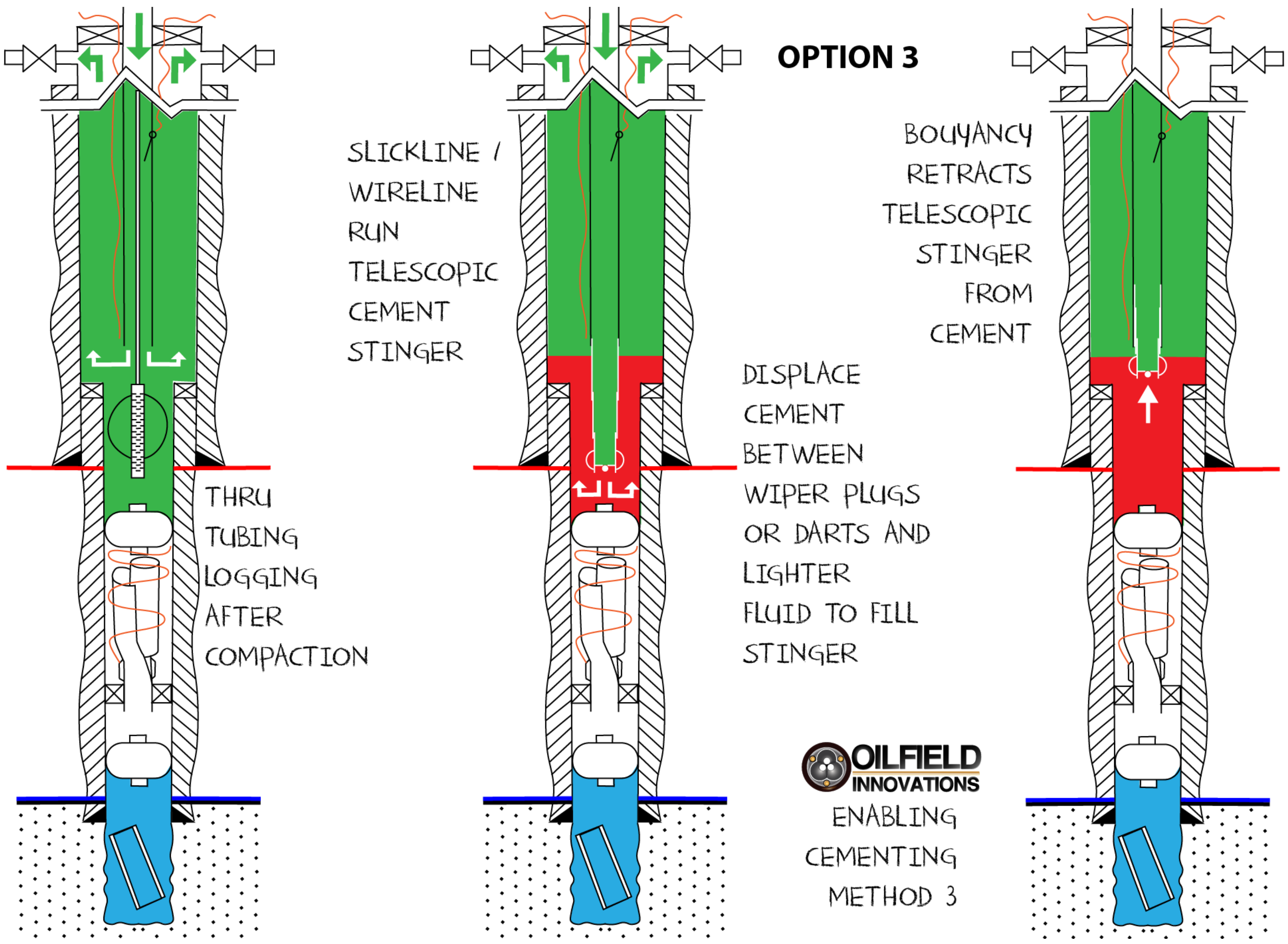


B.3.1 Oilfield Innovations Enabling Option 1 and 2 Methods of Cementing



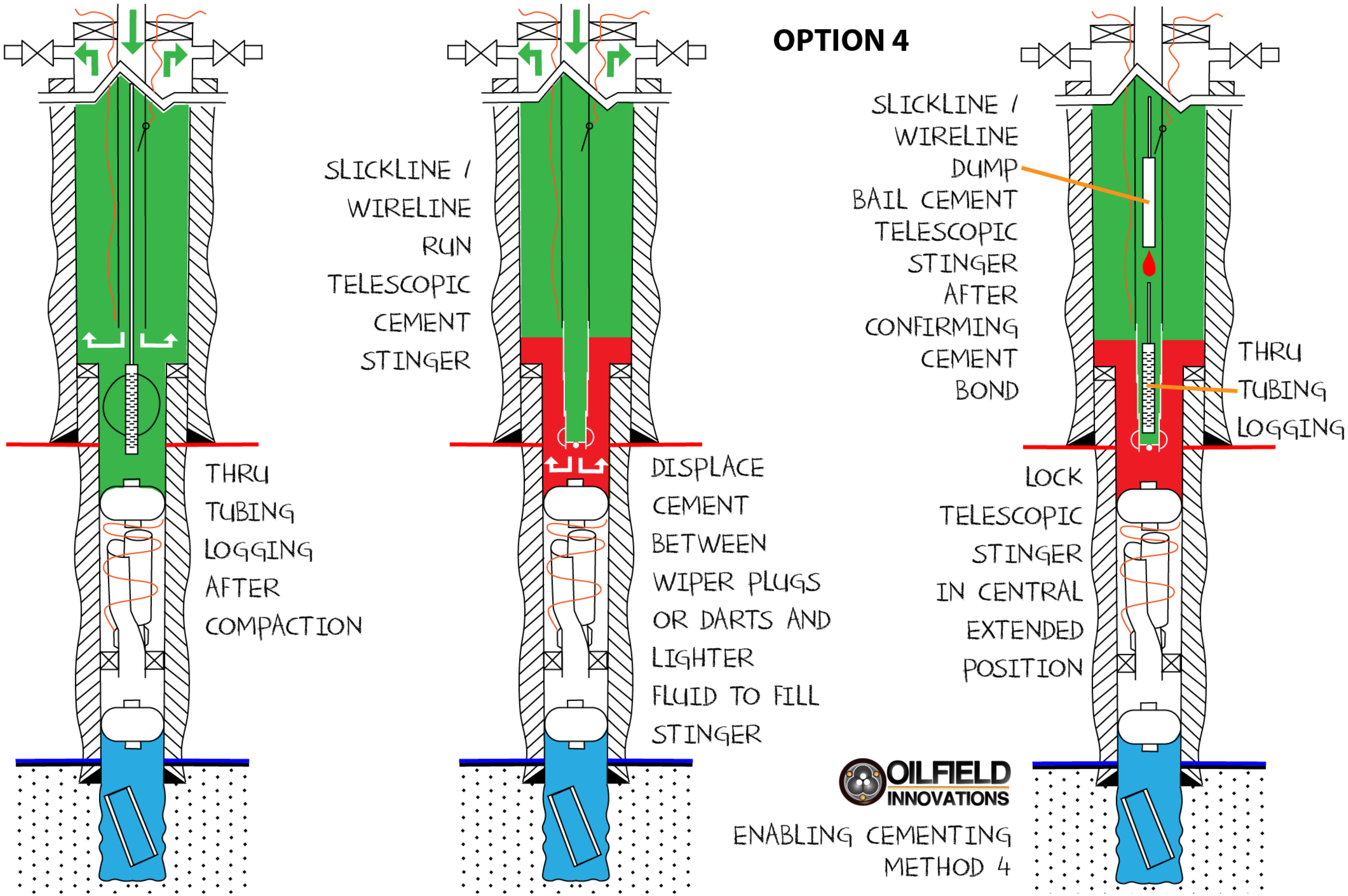
Refer to the right schematic diagram of Section 7 for an overview of how the above fits into the overall enabling method.

B.3.2 Oilfield Innovations Enabling Option 3 Method of Cementing



Refer to the right schematic diagram of Section 7 for an overview of how the above fits into the overall enabling method.

B.3.3 Oilfield Innovations Enabling Option 4 Method of Cementing



Refer to the right schematic diagram of Section 7 for an overview of how the above fits into the overall enabling method.

B.4 LSA and the lack of Cement Adhesion to Dirty or Contaminated Surfaces

B4

O&G TYPE 3&4 COST DRILLING RIG

Root Cause:

Dirty or Low specific gravity (LSA) normally occurring radioactive materials (NORM) are, to some degree, a factor in every well plug and abandonment.

Drilling rig based cleaning of dirty surfaces to provide a wettable surface for cementing (see Section C.2) causes significant waste fluid generation and associated disposal costs.

LSA also causes logistical issues with handling and disposal that increase the cost of well plug and abandonment.

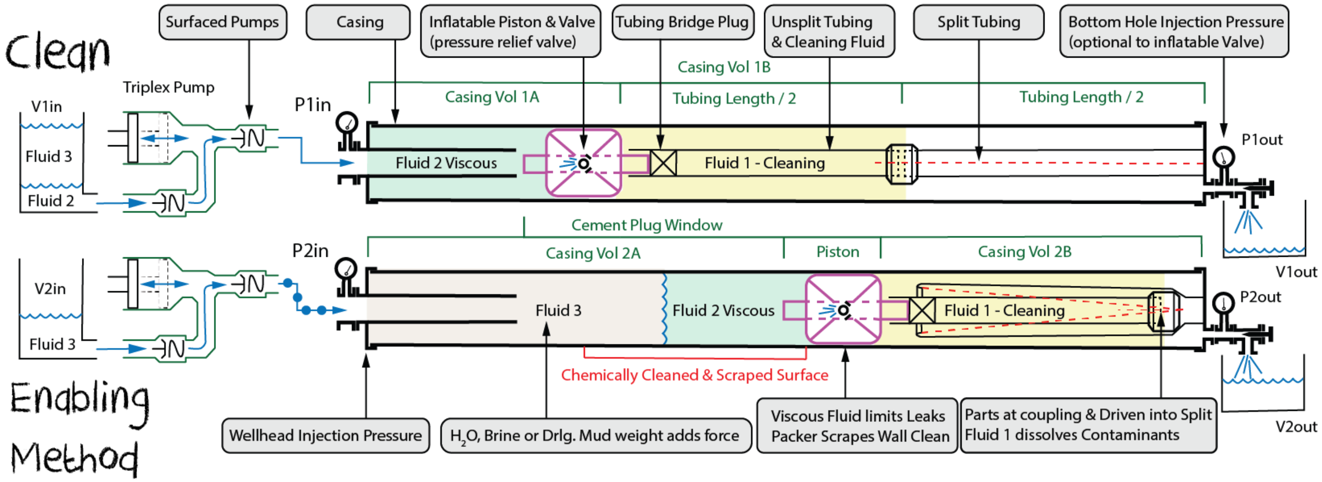
Dirty or contaminated downhole surfaces can cause significant mitigation measures and, hence, are a root causes of high P&A costs.

O&G TYPE 1 COSTS SL & WL

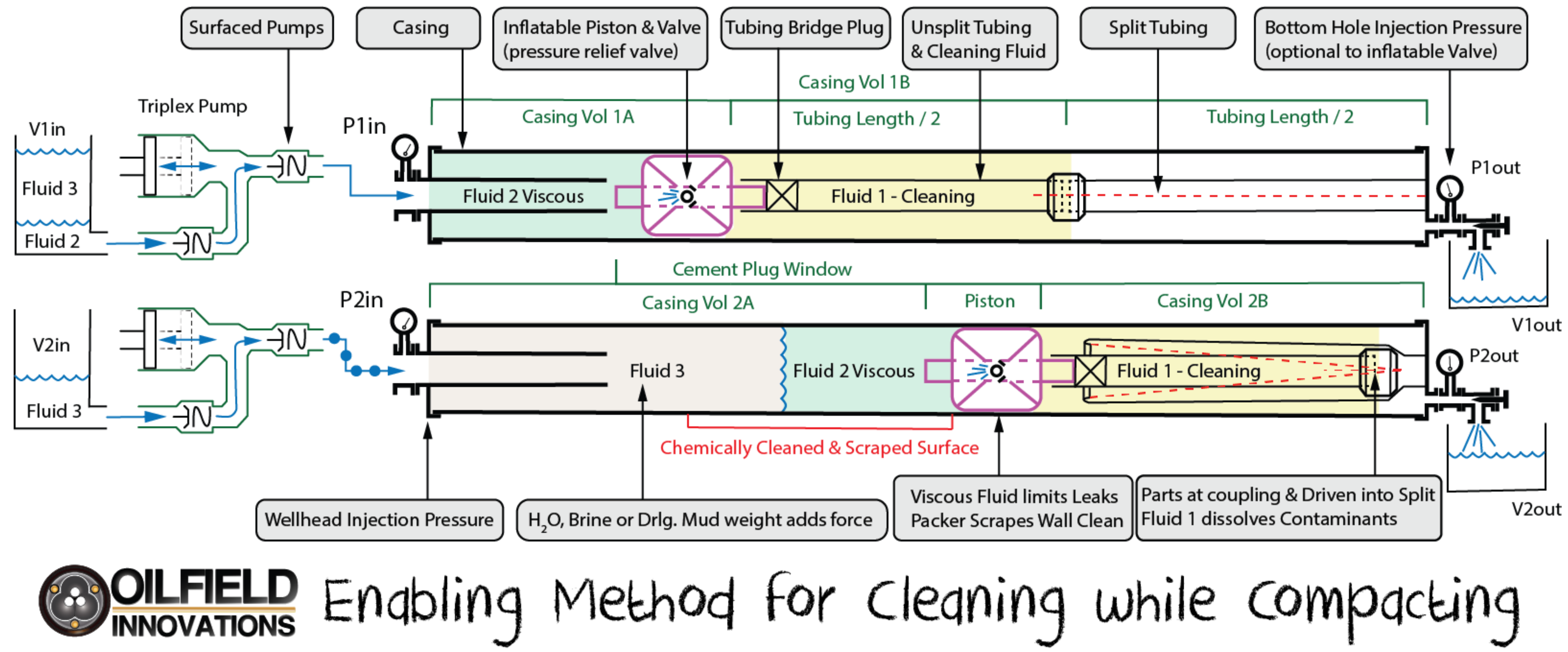
Possible Mitigation:

The best way to lower the cost of LSA contamination is to not pull the tubing. Instead, compact LSA contaminated tubing into the liquid spaces of the well and use chemical soaking and a compacting piston to scrape surfaces clean while using OILtd's enabling method shown to the right and on the following page (also see Section 7) to dispose of contamination downhole.

Cleaning fluids may be placed within the well bore and allowed to soak prior to using the thru-tubing compaction piston to scrape any remaining contamination from the casing walls so as to leave a clean wettable surface for cementing (see Section B.1.1) and avoid bringing contaminates to surface.



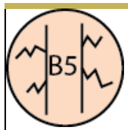
B.4.1 Enlarged View of Oilfield Innovations Enabling Method of Cleaning while Compacting



Refer to the middle diagram of Section 7 for an overview of how the above fits into the overall enabling method.

After splitting the tubing, placing the tubing bridge plug and severing the un-split tubing, and before inflating and pumping against the inflatable piston packer, the cleaning Fluid 1 is placed and allowed to soak. After sufficient chemical cleaning time has occurred, the compaction piston is inflated. The packer can act as a piston within the tubing to force separation where necessary to ultimately expand against the casing inside diameter. Pressure *P1in* is placed against the inflated piston to start compaction of the tubing. As the pressure is increased from *P1in* to *P2in*, slip-like scratchers on the inflatable piston scrape the casing inside diameter as it is pumped downward during compaction. A viscous Fluid 2 is pumped after the piston to improve the seal against the casing and separate any cleaning fluid expelled from the relief valve from Fluid 3, which can be seawater, brine or drilling mud depending upon the pressure integrity of the casing. After logging the cement bond behind the now clean and water wettable inside diameter of the casing, cementing can occur (See Sections B.3.1, B.3.2 and B.3.3).

B.5 Deterioration of Cement Quality during Initial Placement or Production



Root Cause:

The condition of the primary cement between the formation and the casing should be confirmed by cement bond logging before plugging and abandoning any particular part of a well. At the 23rd June 2016 OGA Aberdeen brainstorming event: ConocoPhillips stated that, after logging the cement, they found that it was difficult to predict the quality of the cement using original records. Specifically, ConocoPhillips said that some cement job records indicated potential issues where none existed while other records showed perfect cement placement but significant integrity issues were found.

Tubular-in-tubular eccentricity must be removed before conventional cement bond logging can occur (see Section B.1.2) so that the cement behind casing can be confirmed. Otherwise, it is impossible to verify the cement plug across the wellbore comprises an effective barrier.

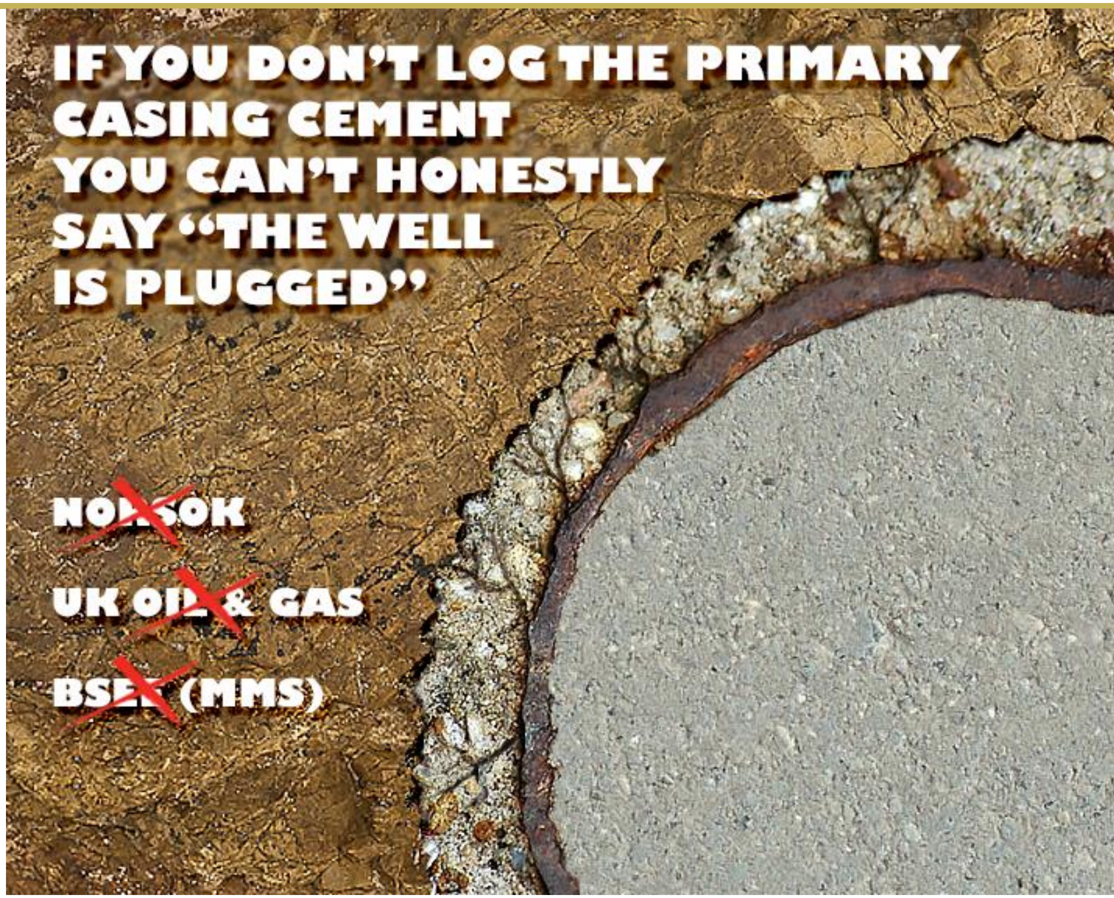
Accordingly, since drilling rigs are typically used to remove the tubing so that cement bond logging can occur, conventional verification that the cement behind the casing was placed correctly and/or has not deteriorated over time, is a root cause of high plug and abandonment costs.

Possible Mitigation:

Verify the cement behind casing without using a drilling rig via the method enabling thru-tubing logging described in Section 7. Having verified the cement behind casing with a lower cost method, determine which wells need a drilling rig abandonment and which wells do not required the additional expense.

Where lacking or poor cementation exists, OILtd's enabling method shown in Sections C.4.1 and C.4.2 can be used to repair well integrity.

For the smaller percentage of well integrity issues that cannot be repaired by OILtd's enabling method described in Sections 7, C.4.1 and C.4.2, a drilling rig can be used to repair the damage.



See Section B.1.1 for the requirements of plug and abandonment well integrity and see section B.1.2 for an explanation of cement bond logging.

B.6 Year Round Shelter for Weather Dependent Operations

B6

O&G TYPE 3&4 COST DRILLING RIG

Root Cause:

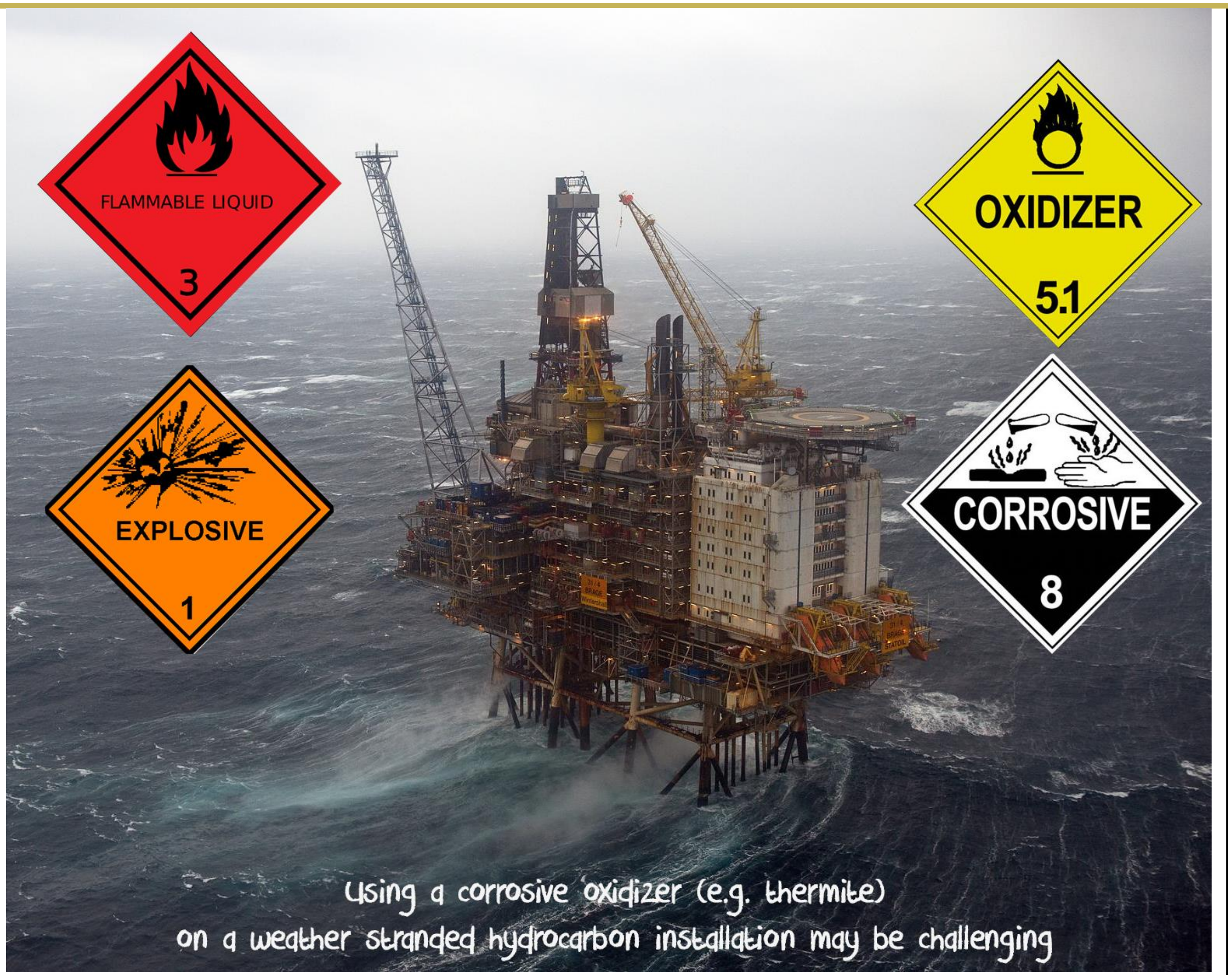
Offshore installations, whether normally manned or normally unmanned, are isolated from support and thus, all operations and transportation are weather dependent. Regardless of whether an mobile offshore drilling unit (MODU) or a platform drilling is used, sheltering operations from the effect of the weather year round is expensive.

Safely producing explosive and flammable hydrocarbons is expensive and the added impact of weather and use of, for example, highly oxidizing and corrosive elements, like thermite, that are capable of melting wellbores or the platform jackets, and which increase risk, can be expensive and dependent upon access, egress and weather. Accordingly, year round shelter for weather dependent or higher risk operations is a root cause of high plug and abandonment cost.

O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

Use non-explosive or non-melting methods and perform campaigns outside of the North Sea winter season. Slickline and wireline crews are relatively small, their equipment is relatively light and occupy a relatively small space for use or storage and, therefore, can be started and stopped more easily than mobile offshore drilling rigs with 40 to 100 people who must be transported to and from shore regularly with larger equipment and support needs. OILtd's enabling method described in Section 7 does not exclude the use of drilling rigs or thermite, but it does allow you to determine if either is needed with less people and environmental risk.



Risks associated with weather preventing access and egress from a platform can limit operations, especially those involving explosives (perforating guns or severance charges) and/or highly oxidizing and corrosive agents like thermite.

C. MATERIAL VOLUMES, PLACEMENT AND DISPOSAL SPECIFICATION

O&G TYPE 3&4 COST DRILLING RIG

Root Cause:

A scope of work may increase until the available resources have been used. This is particularly true for material and fluid volumetric space. Drilling rigs are designed for "drilling," which requires large volumes of fluid and material handling capabilities. When offshore personnel are given the ability to use and store large volumes, it is understandably easier to use said capabilities than look for more time consuming and more efficient ways.

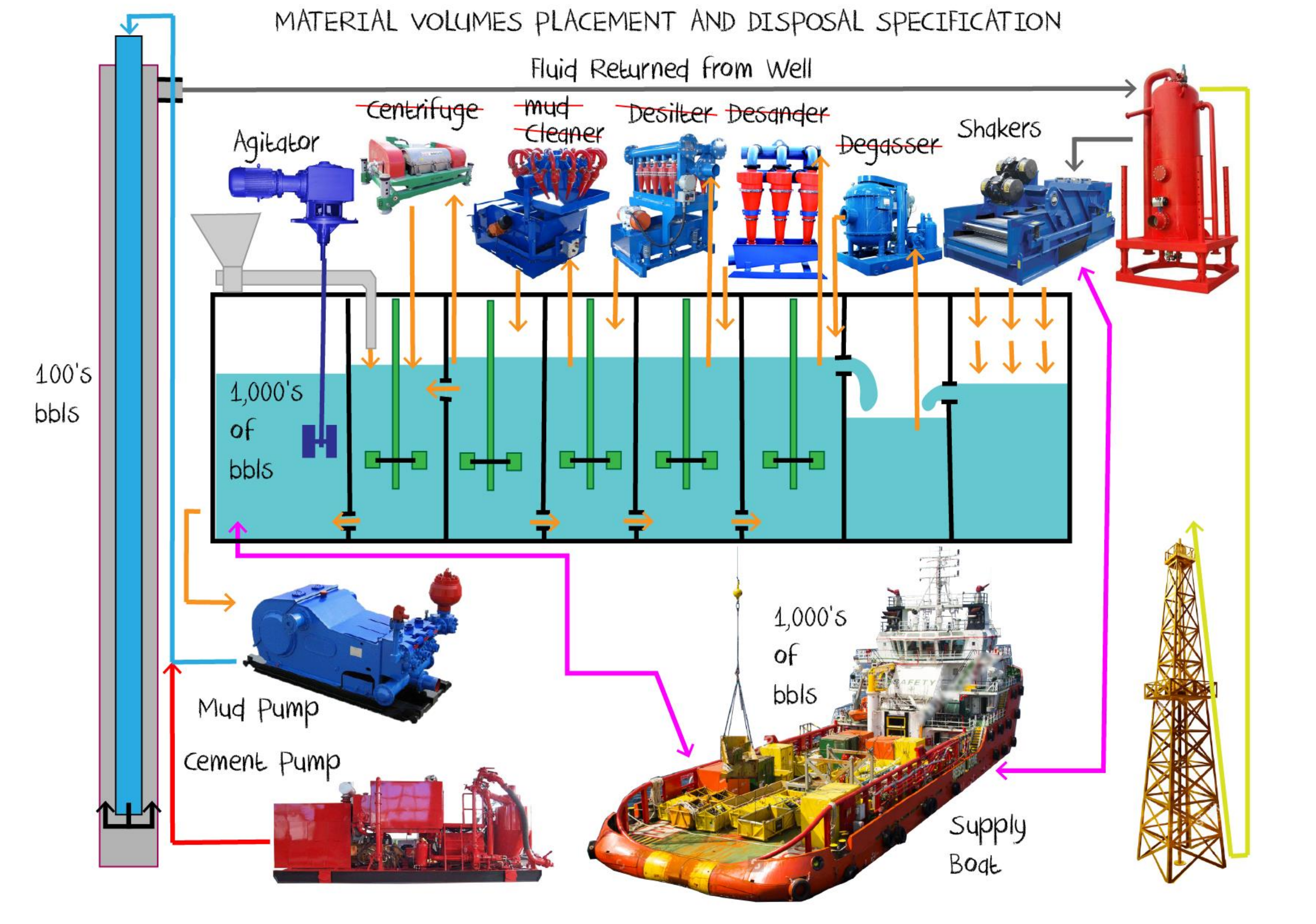
Accordingly, when the O&G UK specify 500 feet of pumped cement to get 100 feet of "*good*" cement (see Section B.1.1) is it because pumping five (5) times more volume that what is needed can be justified based upon the time cost of drilling rig operations and, hence, available drilling rig capacities are a root cause of high P&A costs.

O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

Limit capacities to only what is needed by, for example, putting pumps on the supply boat and using OILtd's enabling method of Section 7 to avoid using a drilling rig. Supply boats have more than enough capacity for well plug and abandonment.

Use a walk-to-work system and cleaning chemicals and OILtd's enabling method to clean and scrape the well and keep waste fluids and materials in the well (see Section B.3.1).



The above describes a drilling rig system, wherein the items marked with a red line are not typically used during well plug and abandonment. The alternative possible mitigation measure being proposed is to place the pumps on the supply boat so as avoid paying for the rest of the drilling rig equipment.

C.1 Large Volume of Cement Lost to High Velocity Channelling

Root Cause:

The O&G UK recommend 500-feet of pumped cement to get 100-feet of "*good*" cement, leaving 400-feet of wasted material, relates to high velocity channelling.

Large fluid and material volumes pumped at high velocities causes channelling and waste that are accepted practice because the time cost of a drilling rig is more expensive than the cost of excess materials and disposal of waste materials.

Gravity and fluid friction around a drilling rig's cement stinger or any tubular within another tubular will cause channelling of fluids pumped at high velocity.

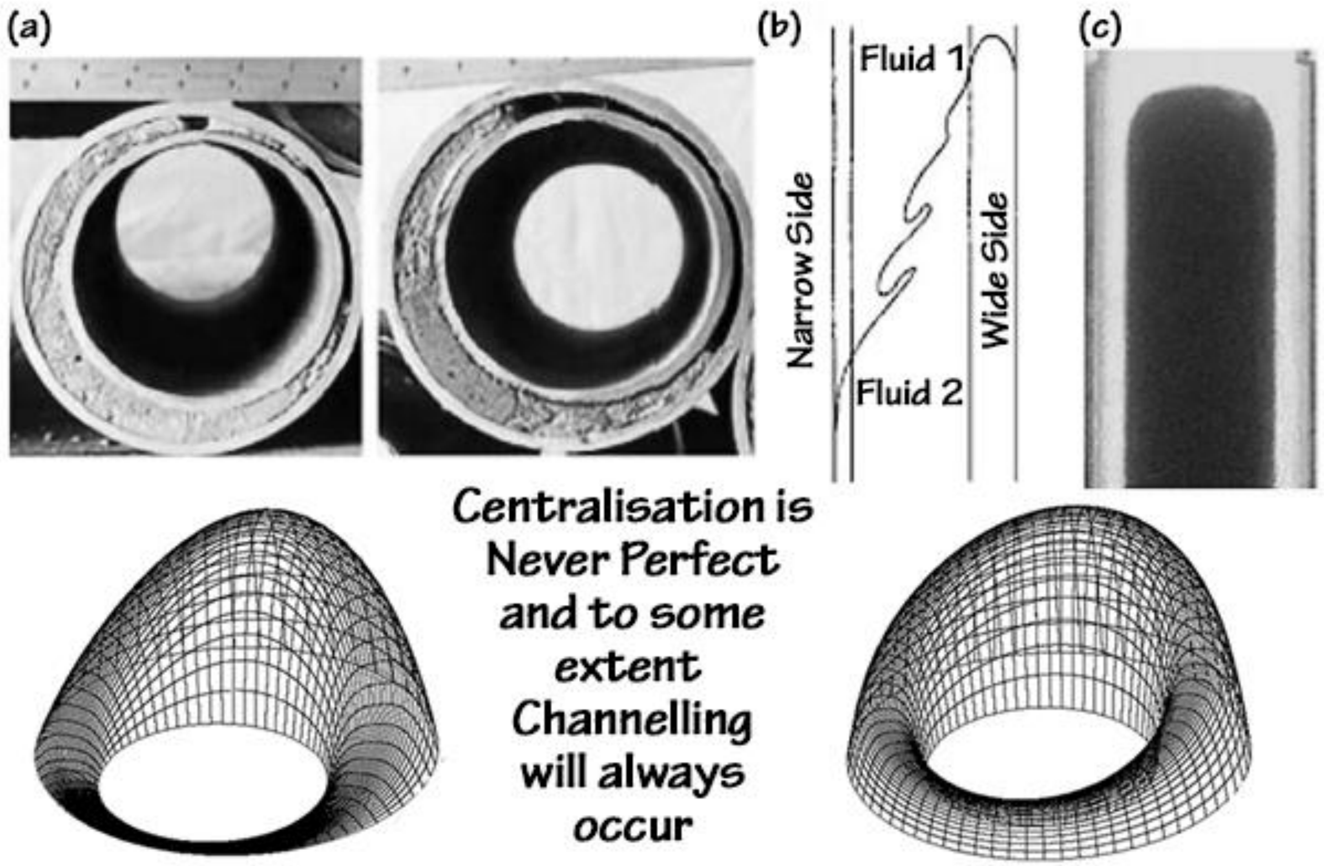
A root cause of high well plug and abandonment cost is the large volumes of fluids pumped at high velocity to save time associated with the cost of a drilling rig.

Possible Mitigation:

Use a different material delivery means. For example, use OILtd's enabling method described in Sections 7, B.3.1, B.3.2, B.3.3 and/or B.4.1 to provide water wet surfaces (see Section B.1.1).

Place 100-feet of cement plus an excess associated with gravity placement interface contamination between two wiper plugs and allow high sg cement to fall through lighter fluids onto the compaction piston support.

Alternatively, use a slickline dump bailer or telescopic stinger to physically place cement.



The poor cement jobs shown in (a) are caused by the fluid friction associated with high velocity pumping as shown in (b). As shown in (c) and illustrated in the 3D wireframes above, friction associated with high velocity pumping of fluids is highest next to the walls of both tubulars where fluid velocity falls to zero. Velocity of the fluid being pumped at a high rate increases the farther away from the frictional effect of the tubular side wall.

C.2 Large Waste Volumes from Well Cleaning & Cementing

Root Cause:

Due to the channelling effect described in Section C.1, the large fluids handling capacity of a drilling rig is used to limit the high time cost of a drilling rig since the generation of waste is relatively cheap in comparison.

Some operators spend time washing LSA (see Section B.3.2) downhole to prevent expensive disposal, and where disposal wells can be used, slop waste fluids may also be disposed of by injection into a depleted well.

When setting cement plugs with five (5) to ten (10) times more volume than is necessary for compliance with guidelines (see Section B.1.1), waste cementing fluid volumes can be significant but are accepted because they represent a lower cost than the rig time necessary for using smaller less wasteful volumes.

Various fluids can be dispensed into the ocean and other waste materials must be sent to shore for processing, but both have environmental and cost impacts.

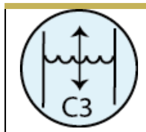
Regardless of the lower marginal cost of disposal relative to the comparable cost of drilling rig time, the high cost of large waste disposal options is a root cause of high well plug and abandonment costs.

Possible Mitigation:

Use lower hourly cost methods that produce less waste. As described in B.4.1, an enabling wireline compaction method can be used to clean and dispose of wasted during compaction to leave a water wettable surface for thru-tubing bond logging (see Section 7) and thru tubing cementing (see Section B.3.1).

Generation of large waste volumes is unnecessary when smaller volumes are used and waste can be disposed of downhole during use of OILtd's enabling method described in Section 7.

C.3 Large Quantity of Material and Non-Productive Time to Establish & Maintain Well Control



Root Cause:

A drilling rig's equipment is unsuited to pressurized or vacuum thru-tubing operations and, hence, is typically not used during Phase 1 reservoir plugging so as to avoid an unstable fluid barrier associated with exposure to a depleted reservoir.

Drilling rigs can strip through blowout preventers (BOP) in extreme conditions, but generally cannot work efficiently unless the well is open to atmospheric pressure with a stable fluid column barrier as shown to the right.

A drilling rig uses a fluid column barrier that has a weight higher than the pore pressure of the rock formations. Provided the effective weight of the fluid column barrier never exceeds the fracture pressure of the rock formations the fluid column barrier should remain stable.

The stability of the fluid column barrier is monitored by stopping any pumping operations and measuring whether the well is gaining fluid or losing fluid. The typical accuracy of measurement is about a quarter of a barrel or around 10 gallons of fluid.

If more than 10 gallons of fluid are gained the blowout preventers are shut and heavier fluid is pumped into the well to "kill" it with the heavier fluid.

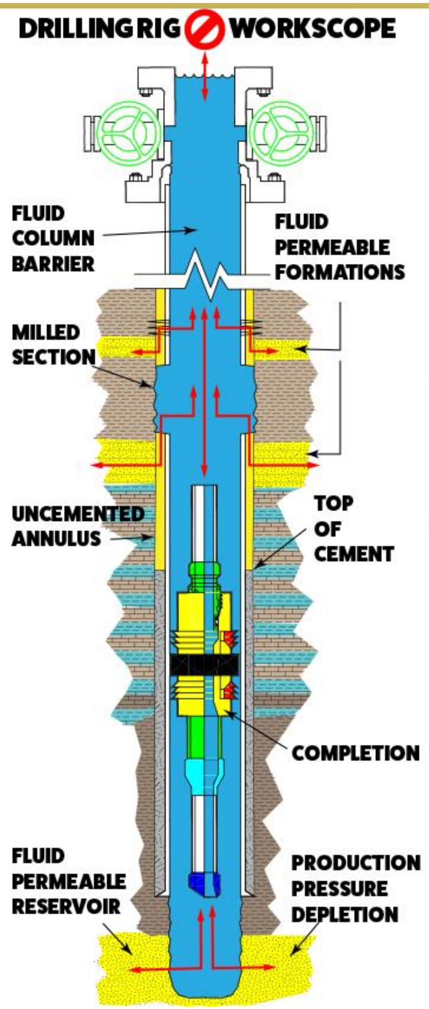
If more than 10 gallons is lost to the well it is monitored closely and materials are added to the fluid column barrier to attempt to plug the leaks.

The process of establishing, measuring and maintaining the fluid column barrier can be a non-productive time (NPT) component of drilling rig operations that can represent a significant cost factor during plug and abandonment operations.

Casing section milling can incur loses or gains and associated NPT through uncemented annuli. Such NPT can be a root cause of high P&A cost.

Possible Mitigation:

Use pressure controlled thru-tubing slickline, wireline or coiled tubing off-the-shelf equipment with OILtd's enabling method (see Sections 7, C.4.1 and C.4.2) to avoid opening the well to atmospheric pressure.



Typically slickline, wireline and/or coiled tubing operations are used during phase 1 of plug and abandonment because a drilling rig cannot work effective if pressure or vacuum conditions exist. When section milling, connection to uncemented annuli and loss/gain zones may cause non-productive time (NPT) and increased cost during P&A.

C.4 Cement Repair, Casing Section Milling and Associated Swarf Problems

C4

O&G TYPE 3&4 COST DRILLING RIG

Root Cause:

Casing section milling within cemented casing takes time and is expensive, but can be carried out effectively… unfortunately if the casing is cemented section milling typically is unnecessary during plug and abandonment.

The lack of casing cementation can be problematic for section milling because the casing can vibrate and can become wrapped around the milling string as shown to the right.

O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

Avoid rig based section milling where ever possible using OILtd's enabling method of shredding casing and repairing or placing cement as shown in the following Section C.4.1.

C.4.1 Oilfield Innovations Enabling Method for Avoiding Casing Section Milling

Root Cause:
Poor or missing casing cementation.

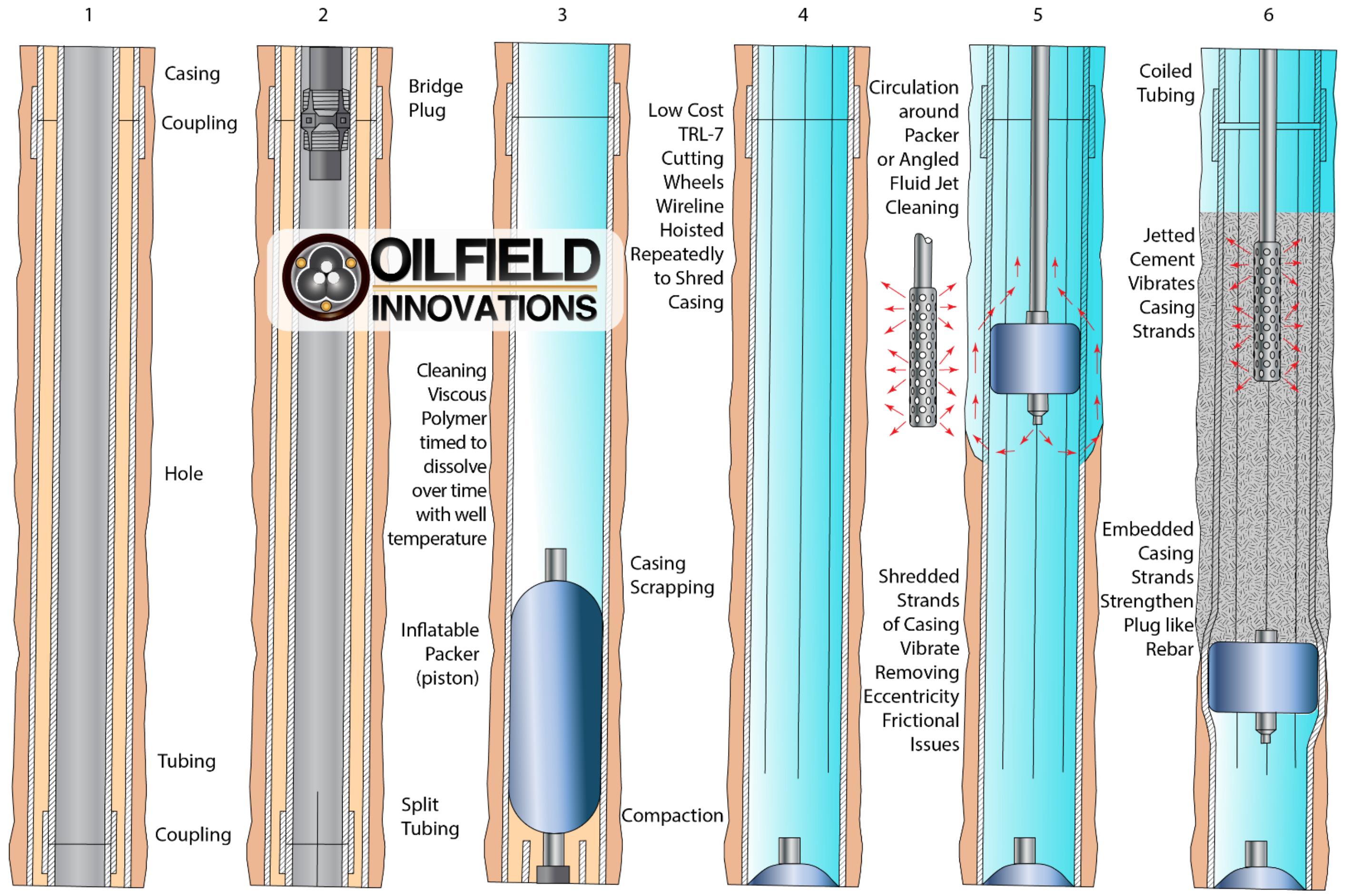
Possible Mitigation:
Column 1 depicts tubing (or casing) within casing that is uncemented. Column 2 shows setting a bridge plug in the tubing (or casing) after splitting the tubing (or casing) for compaction.

Column 3 illustrates a thru-tubing inflatable packer (similar to your car tyre) that has been inflated to clean the casing and compact the tubing (or casing) as described in Section B.4.1.

Column 4 depicts shredded casing used to remove any eccentricity issues (see Section B.1) by removing the casing's ability to shield areas and cause fluid friction.

Column 5 illustrates an inflatable packer on coiled tubing that forces fluid circulation and vibration of the shredded casing strands to clean the casing and well bore. Alternatively, an angled fluid jetting tool can be used to vibrate casing strands and clean both the casing and well bore (see Section C.4.2).

Column 5 shows the inflatable packer initially used to clean fully inflated to expand the shredded casing strands, popping the upper casing coupling, and providing annulus support for jetted cementing operations.



The above method meets O&G UK guidelines (see Section B.1.1) and can be compared to perf and wash methods typically used by drilling rigs to avoid casing section milling (see Section C.4), however perf and wash methods may not satisfy the requirements for a good cement plug (see Sections B.1.1 and C.4.2). The above method can provide annulus cement support and vibrate shredded strands of casing to provide re-bar like cement plug reinforcement to, thus, improve the strength of well abandonment plugs.

C.4.2 Oilfield Innovations Method of Vibration Assisted Cleaning and Cementation

Root Cause:

Cleaning behind uncemented or poorly cemented casing to meet the water wettable surface requirement for a permanent abandonment plug (see Section B.1.1) can be difficult and, hence, .expensive casing milling may be undertaken to remove the casing.

Possible Mitigation:

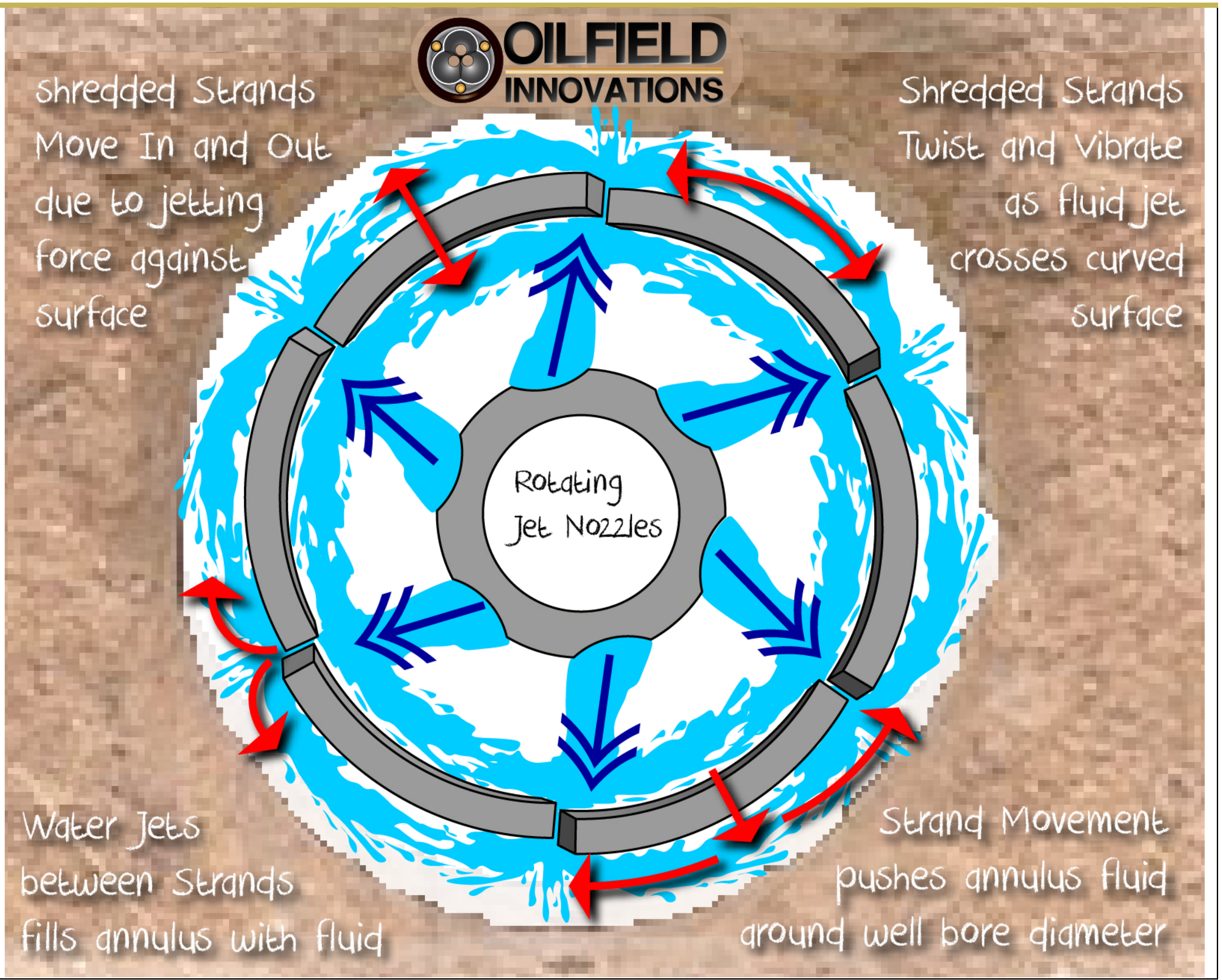
Use coiled tubing with OILtd's enabling method described in C.4.1 to vibrate shredded casing strands to improve cleaning and cementing.

The inside diameter of the shredded casing has a sail-like shape and, hence, when a fluid jetting force hits the curved surface it applies force to move the shredded casing strand inward and outward while vibrating and twisting the strand as the jet crosses the curved surface.

Pushing the shredded strands increases the space between strands and fluid can be jetted into the annulus.

Fluid already in the annulus, or newly jetted into the annulus, is pumped or pushed across the well bore surface by the moving and vibrating shredded casing strands.

Jetting cleaning fluid can provide a water wettable well bore surface and jetting cement into the annulus while vibrating the shredded casing strands creates a rebar-like strengthening effect.



C.4.3 Perf-and-Wash Option

Root Cause:

Poor or lacking casing cementation.

O&G TYPE 2 COSTS CT

Possible Mitigation:

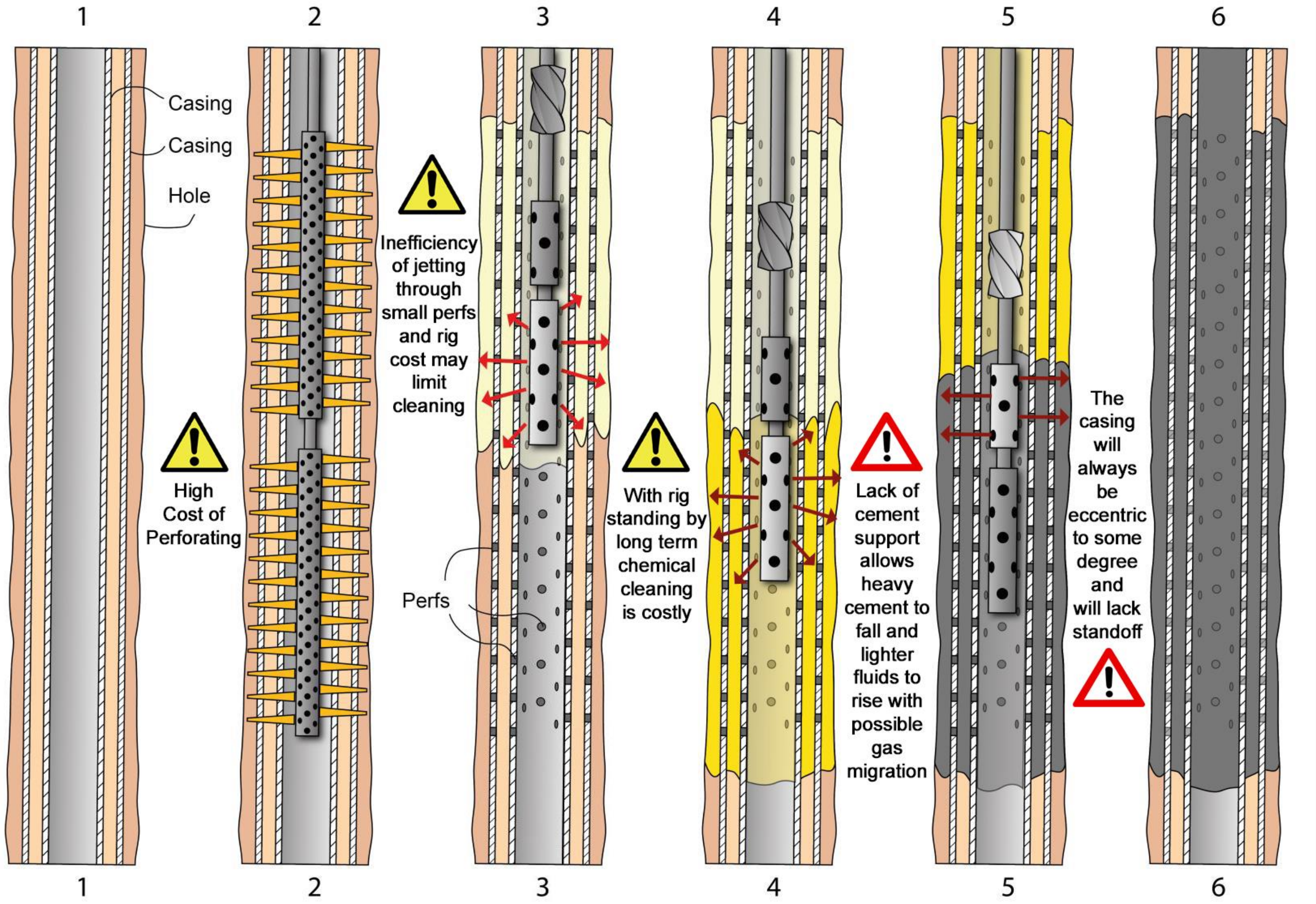
The Perf and wash method, shown to the right, is primarily marketed as a rig based replacement to casing section milling, but it could be used with coiled tubing.

Use of the method described in Section 7 also enables the rig-less use of a perf and wash method, albeit the perf and wash method may not meet the O&G UK guidelines (see Section B.1.1) in every rig based situation where the cost of rig time is high and the cost of Perf and Wash is marginally lower.

Column 1 describes uncemented casing in casing. Column 2 shows perforating small holes through the uncemented casings. Column 3 depicts jetting through the small perforations to clean behind the innermost casing.

Column 4 depicts washing behind the casing through the small perforation holes while column 5 shows cementing through the small holes and column 6 illustrates the final cementation.

While explosives and perforating are expensive, they can be justified by the drilling rig time savings. Since the time cost of thru-tubing operations can be ten (10) or more times less than a drilling rig, the explosive free method described in Section C.4.1 can have a lower cost while meeting O&G UK guidelines (see Section B.1.1).



Perf and Wash can be used with the rig-less enabling method described in Section 7. The significant cost of perforating may have a lower cost than the time a drilling rig would spend casing section milling, but perforating is more expensive than the alternative method described in Section C.4.1. The primary drawbacks of perf and wash are the small perforations that may not provide sufficient cleaning and the lack of support within the annuli where cement may fall through lighter fluids or gas may migrate thru newly placed cement (see Section B.3).

D. METHOD OF REMOVING DOWNHOLE COMPLETION AND CASING INTERFERENCE

Root Cause:

The conventional root cause of high plug and abandonment costs is the use of a drilling rig to remove downhole completion and casing interference.

Drilling rigs have the distinct advantage of being able to section mill casing.

When conventional selection of a drilling rig is based upon the uncertain need to section mill casing when, for example, section milling is only needed in only 20% of the cases, pulling the completion and casing becomes a root cause of high P&A costs for the other 80% of P&A.

.

Possible Mitigation:

Remove the interference of the completion in a different way. Use OILtd's enabling method described in Section 7 for Phase 1 & 2 plugging of +/- 80% of the wells that do not require casing section milling.

Phase 3, rigless severance and jacking can be used to remove wellheads while reverse cementing, i.e. pumping down the annulus with returns up the other annuli or tubular bore can be used to set the Phase 3 surface plug prior to said severance and jacking (see Section E.5).

D.1 Reversal of Installation Process

Root Cause:

Reversing the installation process by pulling the tubing to remove interference from the completion satisfies a natural curiosity to "*physically see*" the completion, but pulling is not necessarily cost efficient because completions are designed to be more or less permanent so as to contain hydrocarbons with at least two barriers and provide a sufficient flow rate for production.

Pulling tubulars is not typically cost efficient because it drives the selection of a drilling rig and, hence, makes plug and abandonment very expensive. Using an expensive drilling rig does not guarantee P&A to the appropriate guidelines (see Section B.1.1) unless sufficient time and expense is used to confirm cementation behind casing or casing section milling is undertaken.

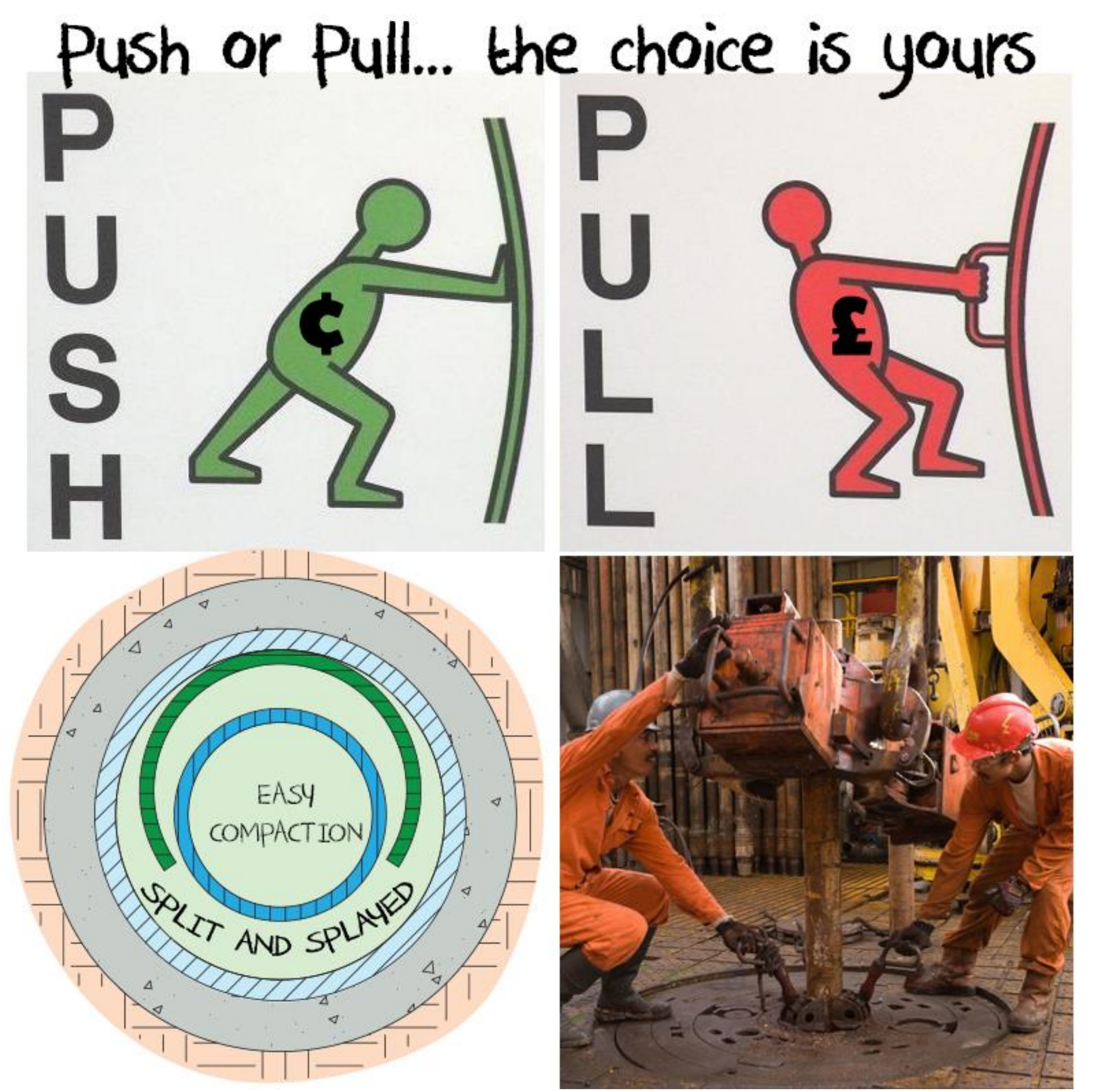
Possible Mitigation:

Recognise the expense associated with the "*natural curiosity to physically see the completion*" and, instead of pulling the completion, push the completion into the liquid space of the well and compact it (see Section B.1).

As shown to the right, splitting the tubing vertically and splaying the split tubing is an easy way to compact a whole piece of tubing with a split piece of tubing and achieve at least a 50% compaction ratio that yields an unobstructed logging and cement space.

Wells can be from, for example, 9,000 to 10,000 feet or 2700 to 3000 metres deep. Effectively placed abandonment plugs (see Section B.1.1) can be a 100 feet or 30 metres in depth. Accordingly, splitting 100 feet (or 30m) of tubing vertically and then severing and driving 100 feet (or 30m) of whole tubing into the split tubing, provides enough space for thru-tubing logging of the casing cement and placement of a 100-ft (or 30m) cement abandonment plug (see Section 7).

Why pull when pushing is significantly less expensive?



D.1.1 Mitigation – Compaction Verification

Root Cause:

An unrealistic perception that OCTG (Oil Country Tubular Goods) are somehow stronger than the common grades of steel they are made of, causes the misconception that it is hard to split or shredded and compact tubing or casing.

O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

The compaction of OCTG (2 3/8” tubing inside of 5 ½” casing shown to the right) has been verified using a common garden variety pump and common cement wiper plugs.

Verification of +/- 50% compaction has been carried out under the worst frictional condition of horizontally compacting shredded tubing.

Compaction of a split tubing in an vertical or inclined well bore will have lower frictional values and, hence, yield higher compaction ratios with less applied force.

D.1.2 Mitigation – Use Large Cross Section Area to Push and Compact Tubulars

O&G TYPE 3&4 COST DRILLING RIG

Root Cause:

Completion equipment and eccentric tubing interfere with logging and cementing.

Pulling the completion with a drilling rig is very expensive.

O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

As depicted in the bottom left illustration of Section D.1 splitting, splaying and compacting tubing within the casings does not consume a lot of space and, hence, pressure applied to the large cross sectional area within the casing can easily generate sufficient force to yield the small cross section area of the tubing steel and compact tubulars into the liquid spaces of the well..

As shown to the right, seawater or heavier fluids can be used within the cross section area of the casing and pressure can be applied at surface to exert huge forces during compaction.

For example, the table to the right shows the force at 6000 feet, or 1830 metres, for application of 10-ppg (1.2 sg) brine within 9 5/8" casing using 3,000-psi, or 225 bar, surface pressure to generate 195,000 lbs, or 95,225 kilograms, of force, which far exceeds the cross sectional ultimate yield strength of the steel.

The forces available for the compaction of tubing and completion equipment far exceeds the necessary forces for crushing tubular steel.

Generally speaking, seawater can be used as a compaction fluid with the option of using heavier fluids to, for example, split and compact a production packer or casing within casing.

Where casing pressure integrity is an issue, viscous water based drilling muds with lost circulation material (LCM) can be used.

Available Compaction Force at 6,000' (1830m) by Casing Size and Fluid

	Surface Pressure (psi)	0	1000	2000	3000	4000	5000	6000
	Depth TVD (feet)	6000	6000	6000	6000	6000	6000	6000
Casing Size	Fluid	Pounds of Force Against Compaction Piston						
7" (6" ID)	Seawater	-	28,274	56,549	84,823	113,097	141,372	169,646
9 5/8" (8.5" ID)	Seawater	-	56,745	113,490	170,235	226,980	283,725	340,470
13 3/8" (12.25" ID)	Seawater	-	117,859	235,718	353,576	471,435	589,294	707,153
7" (6" ID)	10-ppg NaCL Brine	12,350	40,625	68,899	97,173	125,448	153,722	181,996
9 5/8" (8.5" ID)	10-ppg NaCL Brine	24,786	81,531	138,276	195,021	251,766	308,511	365,256
13 3/8" (12.25" ID)	10-ppg NaCL Brine	51,481	169,340	287,198	405,057	522,916	640,775	758,634
7" (6" ID)	11.6-ppg CaCL2 Brine	26,465	54,739	83,013	111,288	139,562	167,836	196,111
9 5/8" (8.5" ID)	11.6-ppg CaCL2 Brine	53,113	109,858	166,603	223,348	280,093	336,838	393,583
13 3/8" (12.25" ID)	11.6-ppg CaCL2 Brine	110,316	228,175	346,033	463,892	581,751	699,610	817,469
7" (6" ID)	14-ppg WBM	47,637	75,911	104,185	132,460	160,734	189,008	217,283
9 5/8" (8.5" ID)	14-ppg WBM	95,604	152,349	209,094	265,839	322,584	379,329	436,074
13 3/8" (12.25" ID)	14-ppg WBM	198,569	316,427	434,286	552,145	670,004	787,863	905,721
	Surface Pressure (bar)	0	75	150	225	300	375	450
	Depth TVD (metre)	1830	1830	1830	1830	1830	1830	1830
Casing Size	Fluid	Kilograms of Force Against Compaction Piston						
7" (6" ID)	Seawater	-	13,947	27,894	41,842	55,789	69,736	83,683
9 5/8" (8.5" ID)	Seawater	-	27,991	55,983	83,974	111,965	139,956	167,948
13 3/8" (12.25" ID)	Seawater	-	58,138	116,275	174,413	232,550	290,688	348,826
7" (6" ID)	1.2 sg NaCL Brine	5,606	19,553	33,500	47,448	61,395	75,342	89,289
9 5/8" (8.5" ID)	1.2 sg NaCL Brine	11,251	39,242	67,233	95,225	123,216	151,207	179,198
13 3/8" (12.25" ID)	1.2 sg NaCL Brine	23,368	81,505	139,643	197,781	255,918	314,056	372,193
7" (6" ID)	1.4 sg CaCL2 Brine	12,013	25,960	39,907	53,854	67,802	81,749	95,696
9 5/8" (8.5" ID)	1.4 sg CaCL2 Brine	24,109	52,100	80,091	108,083	136,074	164,065	192,056
13 3/8" (12.25" ID)	1.4 sg CaCL2 Brine	50,074	108,211	166,349	224,487	282,624	340,762	398,899
7" (6" ID)	1.68 sg WBM	21,623	35,570	49,517	63,464	77,412	91,359	105,306
9 5/8" (8.5" ID)	1.68 sg WBM	43,396	71,387	99,378	127,370	155,361	183,352	211,344
13 3/8" (12.25" ID)	1.68 sg WBM	90,133	148,270	206,408	264,545	322,683	380,821	438,958

D.1.3 Mitigation: Use Small Hand Size Tooling with Low Manufacture and Lost in Hole Cost

Root Cause:

The availability of space and resources can be limited on offshore platforms, which often drives companies to the largest and most expensive option comprising the use of drilling rig equipment.

Possible Mitigation:

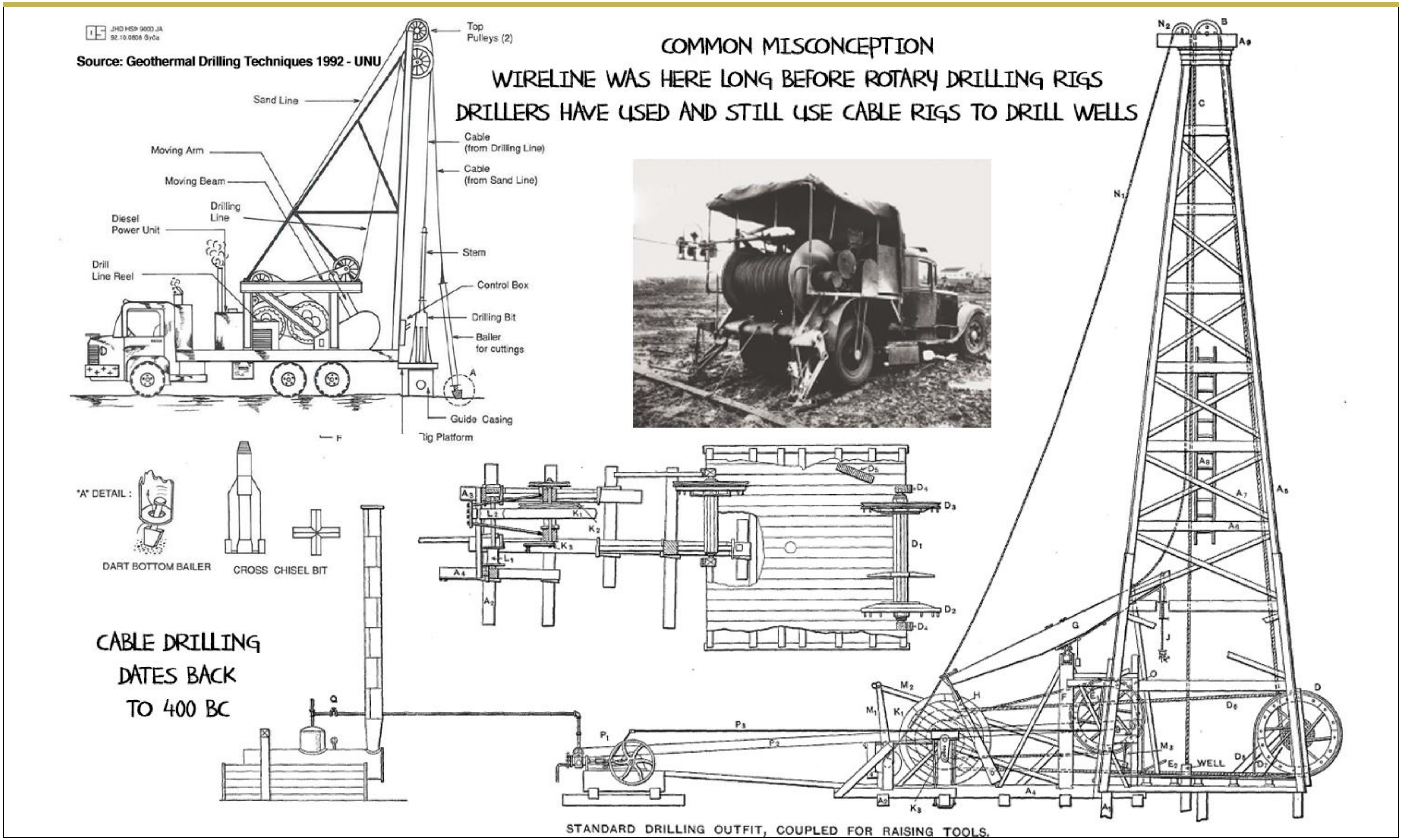
Use the large inventory of proven off-the-shelf TRL-7 hand sized equipment to perform thru-tubing plugging and well abandonment (see Section F.2.1).

As shown to the right, slickline and wireline tooling is relatively small and significantly less expensive that drilling rig equipment.

One of the advantages of many non-electric slickline and wireline tools is their simplicity and the ability to be refurbished and/or repaired on site by personnel carrying out the work.

The small size, low complexity and associated low manufacturing costs mean that tools that become stuck or otherwise lost downhole can be left and compacted with the rest of the completion so as to remove the desire to fish the tools from the well when unexpected events occur.

D.1.4 Common Wireline or Cable Tool Misconception



D.1.5 Mitigation: Use Strong Wire and where the unplanned occurs… DON'T FISH … COMPACT

Root Cause:

Rotary Drillers use large robust and expensive tooling and love to criticise wireline or cable tools as being insignificant and weak.

Those unware of the history of drilling are sometimes convinced that wireline and cable is not a realistic option. This misconception is a root cause of high P&A costs.

Possible Mitigation:

As shown in D.1.4, on the previous page, wireline and cable have been used since around 400BC and are still used today to drill wells and perform well intervention. As shown to the right thin slickline and braided wireline can operate a loads between 30% and 200% of the weight of the average US car (which may be significantly heavier than the European average).

As described in D.1.2, because the simple hand sized tooling has a low cost, when adverse situations occur the tool string can be left downhole and compacted with the completion.

Approximate Specifications and Load Limits for Slickline and Non Conductor Braided Line

Line Size inches diameter	Min. Break Strength	Max. Break Strength	Operating at 65% of min.	Compared to avg. US car (4000lbs)
0.092	1828 lbs	2020 lbs	1188 lbs	30%
0.108	2455 lbs	2712 lbs	1596 lbs	40%
0.125	3203 lbs	3534 lbs	2082 lbs	52%
3/16 braided		6400 lbs	3200 lbs	80%
1/4 braided		11400 lbs	5700 lbs	143%
5/16 braided		16200 lbs	8100 lbs	200%

Since about 400 BC and the beginning of drilling, well operations personnel have been using wireline and cable to successfully drill and intervene in subterranean wells. There is no basis for believing that slickline and braided wireline cannot be used for splitting, severing and placing the necessary tools for OILtd's enabling method shown in Section 7, because such operational loading of wireline is are occurring every day around the world.

D.2 Replace Physical Barrier with Fluid Barrier

Root Cause:

As further described in Section E.1, to work efficiently, a drilling rig must expose the well bore to atmospheric conditions. As discussed in Section C.3, large material and fluid quantities may be required to establish and maintain a fluid barrier.

Accordingly, before a rig can connect its blowout preventers to the well so that it can pull the tubing, it must first remove the production tree barrier that holds down the tubing hanger.

The “safe” removal of the existing production tree barrier and the associated cost of replacing it with a fluid barrier in a safe manner can be a significant cost and, hence, a root cause of high well plug and abandonment costs.

As described in Section D.4, pressurised annuli and well integrity issues are also cost drivers associated with replacing physical barriers with fluid ones.

Possible Mitigation:

Because a rotary drilling rig cannot remove the existing production tree without first having a stable fluid barrier (see Section C.3), slickline, wireline and/or coiled tubing are typically used for Phase 1 reservoir well plugging with the drilling rig functioning as an accommodation vessel and work platform.

An obvious mitigation measure is to “*avoid*” the high cost of replacing a physical barrier with a fluid barrier. Slickline, wireline and coiled tubing can work through the existing barriers by removing the swab cap and connecting to the top of the production tree, as shown to the right.

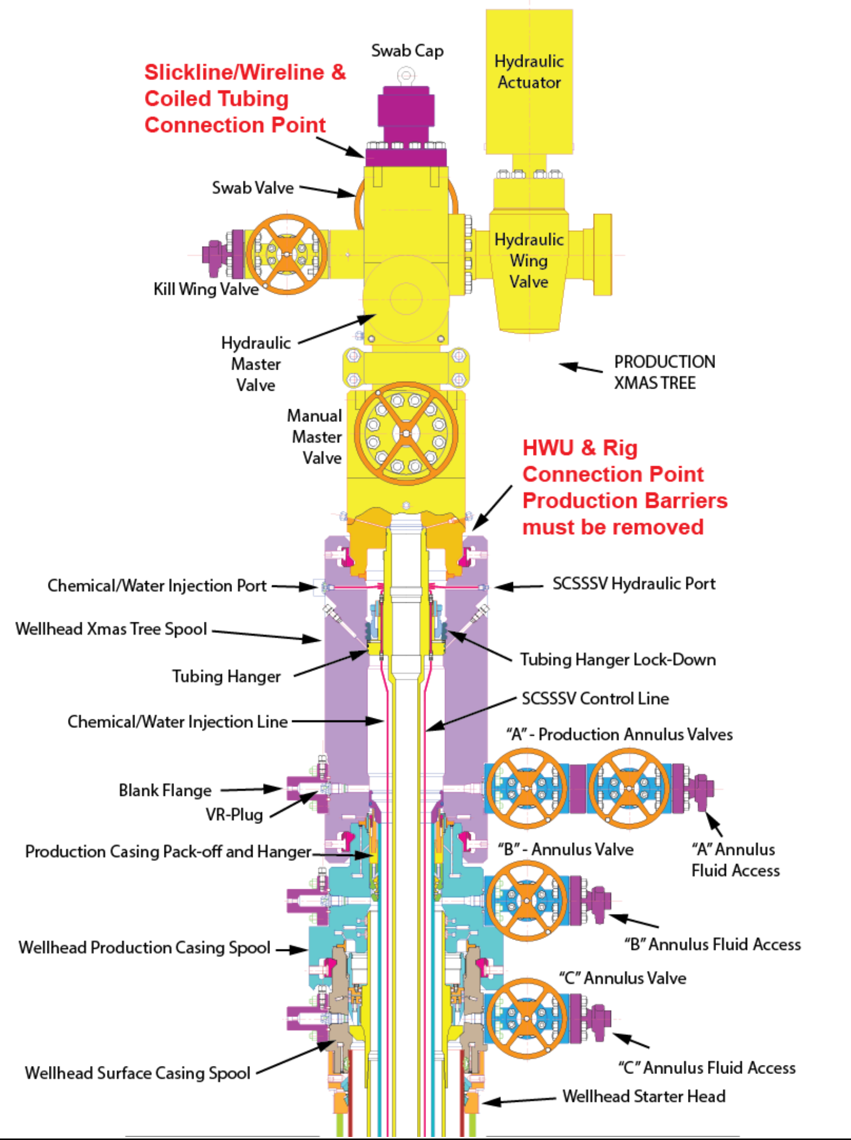
Accordingly, because pressure control equipment can be used, having a pressure or a vacuum within the well has less of an effect on the cost of plugging and avoids the expense of replacing a physical barrier for a fluid barrier.

The use of slickline, wireline and/or coiled tubing can also be used during phase 2 intermediate well plugging using OILtd’s enabling methods described in Sections 7, B.3.1, B.3.2, B.3.3, B.4.1 and C.4.1.

After phase 1 and 2 plugging, pressures or vacuums are isolated and the production tree can be removed safely and cost effectively to allow the phase 3 abandonment of the surface equipment using the rig-less jacking method shown in E.4.5.

As described in Section D.4, well integrity issues can be better managed by leaving existing degraded barriers in place until the well has been plugged.

Accordingly, the cost of well plug and abandonment can be reduced by using the existing barriers instead of replacing them with expensive fluid barriers.



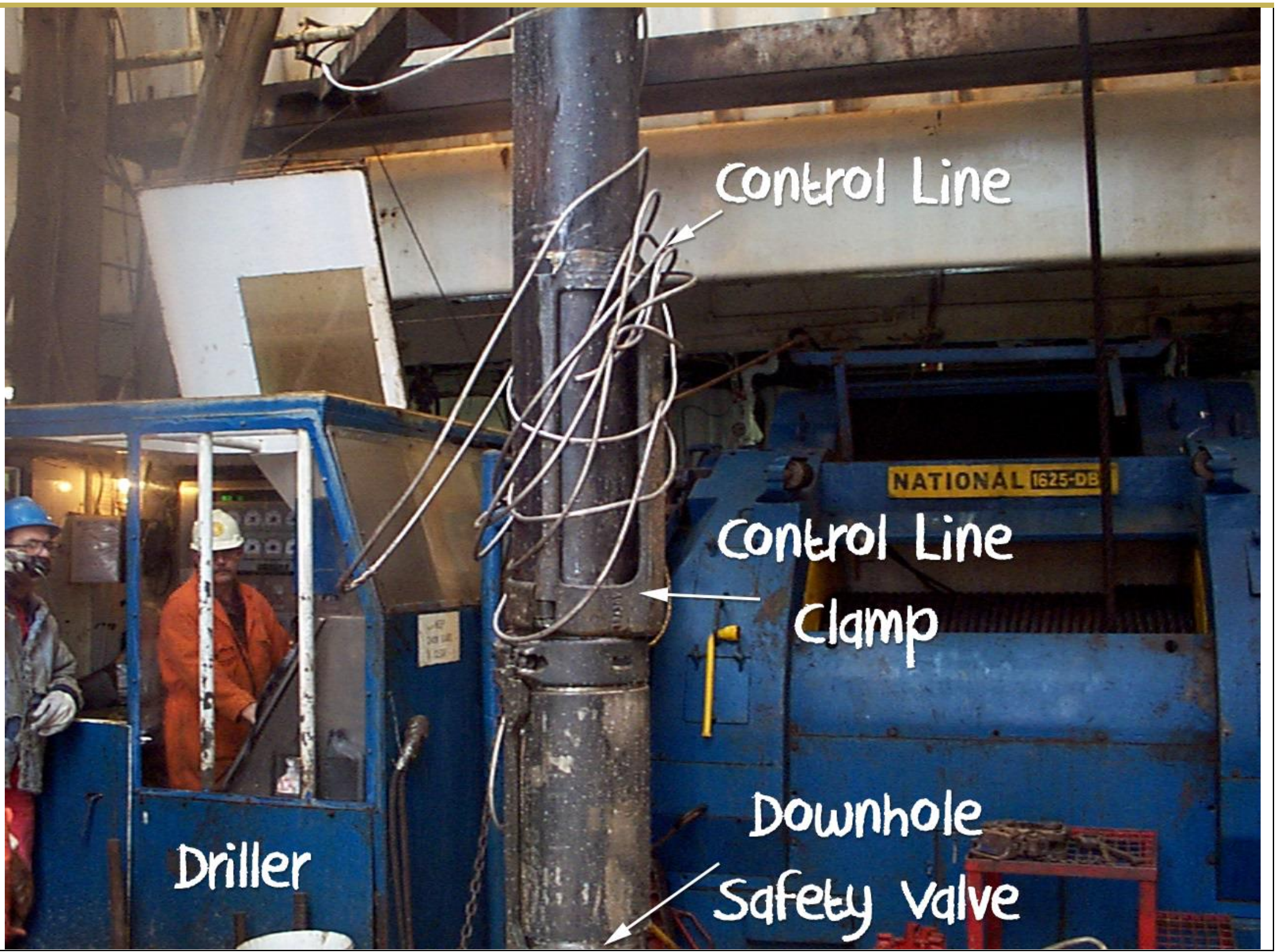
D.3 Handling of Completion, Valves, Cables and Clamps

D3 | O&G TYPE 3&4 COST DRILLING RIG

Root Cause: The pulling and removal of downhole completion equipment, valves, clamps and cables is not necessary an easy task for a drilling rig because such equipment can interfere with the functioning of the blowout preventers, which may not have sufficient capacity to shear the downhole safety valve shown to the right.

O&G TYPE 1 COSTS SL & WL

Possible Mitigation: As described in Section 7, an enabling method can be used to compact completion equipment, including valves, cables and clamps, further into the well so that the compacted equipment can be used to support cement plugs and be disposed of downhole without the risk or cost associated with bringing them back to surface.



D.4 Pressurized Annuli and Well Integrity Challenges

D4 | O&G TYPE 3&4 COST DRILLING RIG

Root Cause:

As illustrated to the right, integrity issues may affect the cost of well plug and abandonment and can comprise: a) the wellhead and production tree, b) the surface controlled sub-surface safety valve (SCSSSV), c) leaks through casing walls between annuli, d) leaks between casing and cement, e) leaks between the production packer and casing, f) leaks from outside the casing into an annulus, g) leaks through cementation, h) leaks between abandonment plugs and casing, i) permeability through cementation, j) leaks between cementation and the strata of the well bore, k) slumping and/or channelling of heavy cement through lighter fluids and l) leaks between tubulars caused by eccentricity of one tubular within another and the inability to overcome fluid frictions close to the contact point.

As the integrity of the plug and abandonment is the ultimate goal of P&A, the mitigation cost of well integrity issues is a root cause of high well plug and abandonment costs.

Because drilling rigs employ many people working directly over any well integrity issue, a root cause of high plug and abandonment costs can also be traced to the mitigation costs of managing well integrity issues for the workforce located directly above the potentially leaking well during rotary drilling rig plug and abandonment.

O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

Minimising the duration and number of people working directly over a well integrity issue can reduce the cost of mitigating well integrity issues.

If existing barriers and degraded or compromised barriers are left in place and supplemented by, for example, sealants or pressure relief systems, then the risks and associated costs of managing well integrity issues a), c), d), f), g), h), i) and j) can be minimised.

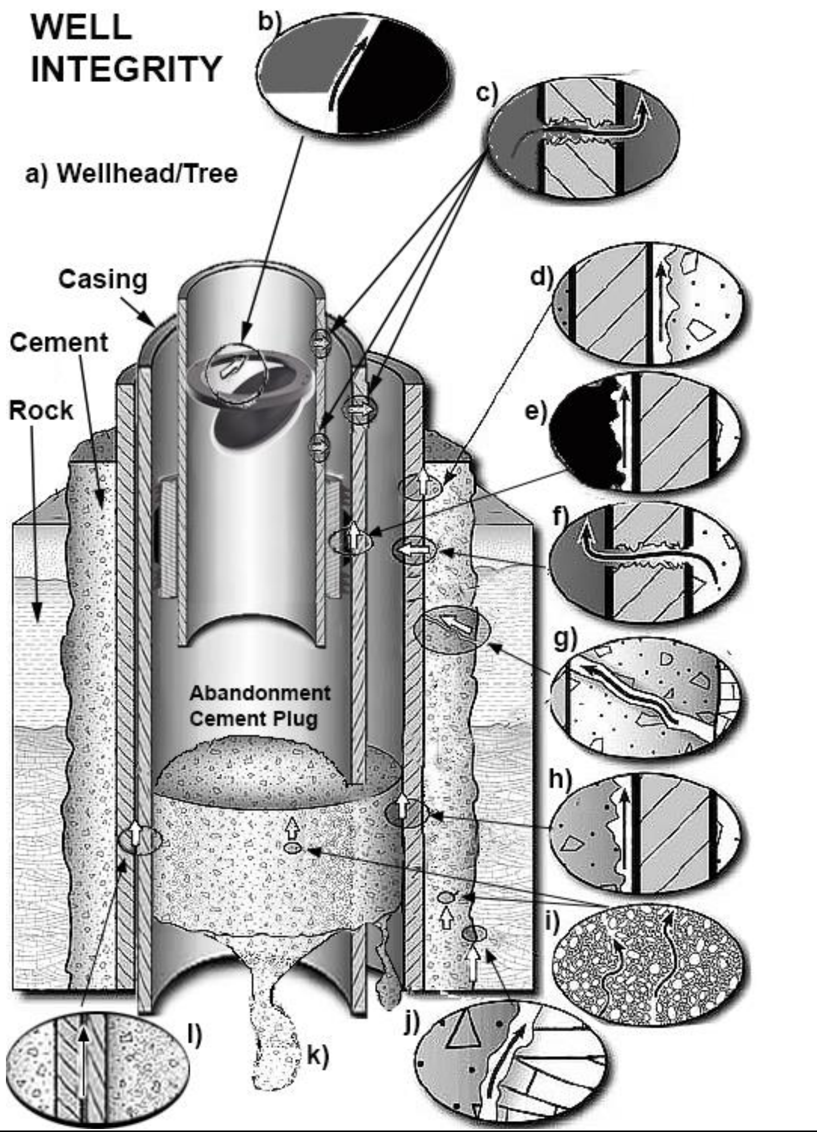
If pressure controlled thru-tubing slickline, slickline, wireline and/or coiled tubing are used the risk and associated costs of well integrity issues b) and e) can be minimised.

OILtd's enabling method described in Section 7 can be used to mitigate the risk and associated cost of the well integrity issues i), k) and l).

OILtd's enabling method illustrated in Section C.4.1 can be used to minimise the risk and cost associated with well integrity issues d), e), f), g) and j).

OILtd's enabling method illustrated in B.4.1 can be used to minimise the risk and cost of well integrity issue h) and l).

Accordingly, for about 80% of the cases not requiring casing section milling, all of the various well integrity issues associated with the existing well and well plugging can be managed by OILtd's enabling methods described herein and, hence, can be used to remove the root cause of high well plug and abandonment costs, i.e. a rotary drilling rig.



D.5 Ineffective Cementing due to Channelling and Gas Migration

D5 | O&G TYPE 3&4 COST DRILLING RIG

Root Cause:

Illustrations a) to e) show instances involving eccentricity, while depictions f) to j) show centralised pipe-in-pipe and k) to p) show flow regimes with an unobstructed pipe diameter.

As shown in the photographs, illustrating c), d), j) and k), poor cementation can occur within any of the scenarios, albeit high velocity placement associated with drilling rig application contributes significantly to the various flow regimes shown.

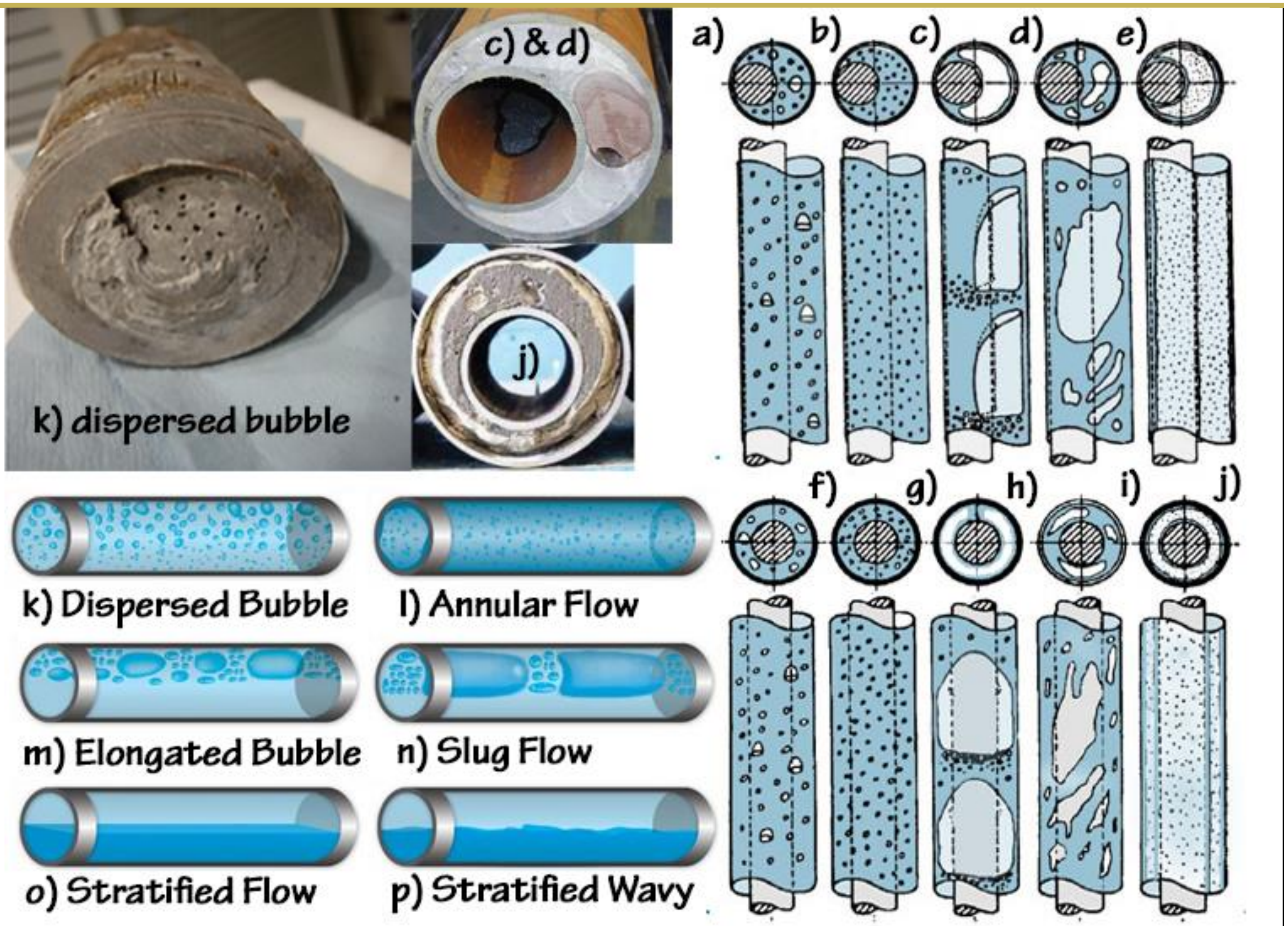
A root cause of high well plugging costs can be described by the mitigation of the various flow regimes when pumping within a system open to atmosphere (i.e. drilling rigs).

O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

As further described in Sections B.3.1, B.3.2 and B.3.3, for example, cement can be segregated with wiper plugs and the descent of heavier cement can be controlled via a pressured controlled system using a choke to control the u-tube pressures.

Accordingly, OILtd's enabling method can remove pipe-in-pipe scenarios and use of a pressurized system and/or bailer, or telescopic stinger, to control the placement of cement and provide stratified flow {see o) to the right} so as to reduce the cost of well plugging.



a) to e) eccentric pipe-in-pipe flow regimes, f) to j) centralised pipe-in-pipe flow regimes, k) to p) flow regimes within an unobstructed pipe diameter

E. MACHINERY SPECIFICATION AND THE CONVENTIONAL DRILLING RIG SELECTION

Root Cause:

One of the smaller sized mobile offshore rotary drilling rigs is shown to the right adjacent to and positioned over a normally unmanned platform (NUI).

From the size difference it is relatively easy to see how over-specified an offshore rotary drilling rig can be.

A root cause of high plug and abandonment cost is the over-specification of equipment needs.

If 20% of wells require section milling then only 20% of wells required a drilling rig and the equipment needs for the other 80% are over specified and result in a significant waste of money that could be used for projects that have a return on investment.

Given the current structural change from offshore to onshore fracking technologies, the survival of the offshore oil and gas industry depends upon reducing cost, whereby every penny not wasted on the over specification of well plugging and abandonment is a step in the right direction.

Possible Mitigation:

Improve the future of the offshore oil and gas sector by not over specifying equipment needs for well plug and abandonment.

Use OILtd's enabling method described in Section 6 to perform phase 1 and 2 well plugging with cost slickline, wireline and coiled tubing operations for the 80% of wells not requiring casing section milling.

Letourneau 116C class drilling rig over a Southern North Sea Normally Unmanned Installation.

E.1 Specification of Open to Atmosphere Operations

Root Cause:

A root cause of high well plugging and abandonment costs is a rotary drilling rig's need to open the well to atmospheric pressure.

Having formations miles and kilometres below the earth's crust held back by only a fluid barrier can be very expensive when many people are working immediately above the open to atmosphere well bore.

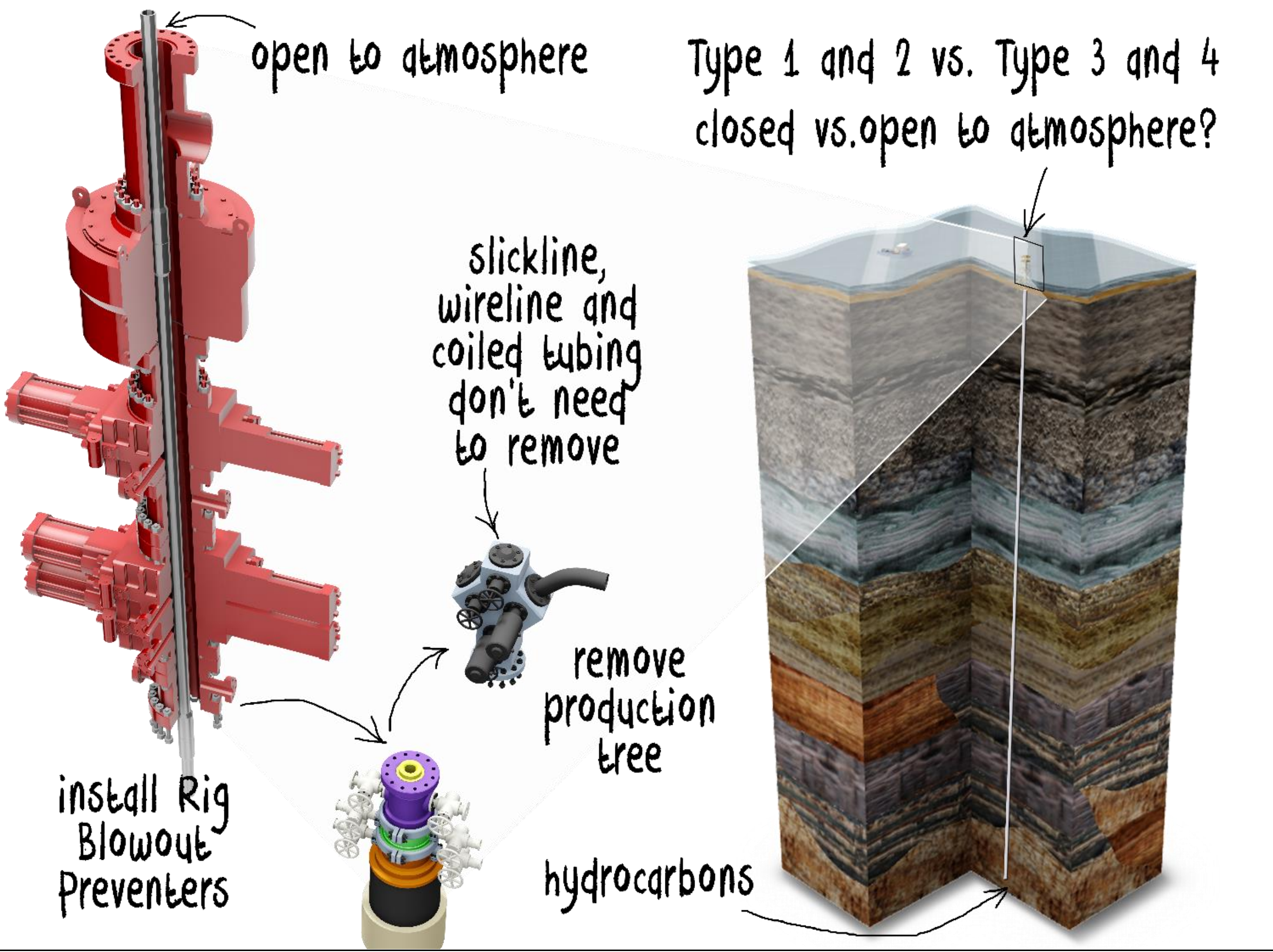
The mitigation measures necessary to establish a fluid barrier and then remove existing barriers to install a drilling rig blowout preventer can be very expensive, whereby maintaining the fluid column barrier (see Section C.3) can be a continuing expense and, hence, is a root cost of high P&A costs.

Possible Mitigation:

Use OILtd's Section 7 enabling method and leave existing barriers in place and work through the production equipment as shown in Sections E.4.4 and F.2.1 to F.2.16 during Phase 1 and 2 well plugging.

Working through existing barriers removes significant layers of cost and, hence, can be a mitigation to the root cause of high well P&A.

Use rig-less jacking equipment described in Section E.5 for phase 3 well abandonment.



E.2 Over specification of Personnel and Material Requirements

Root Cause:

Obviously, the more people employed, the more expensive the operation will be.

Most Mobile Offshore Drilling Units (MODU) can accommodate up 100 people. The minimum crew accommodation is generally 40 people. The crew associated with well plug and abandonment will therefore be between 40 and 100 people.

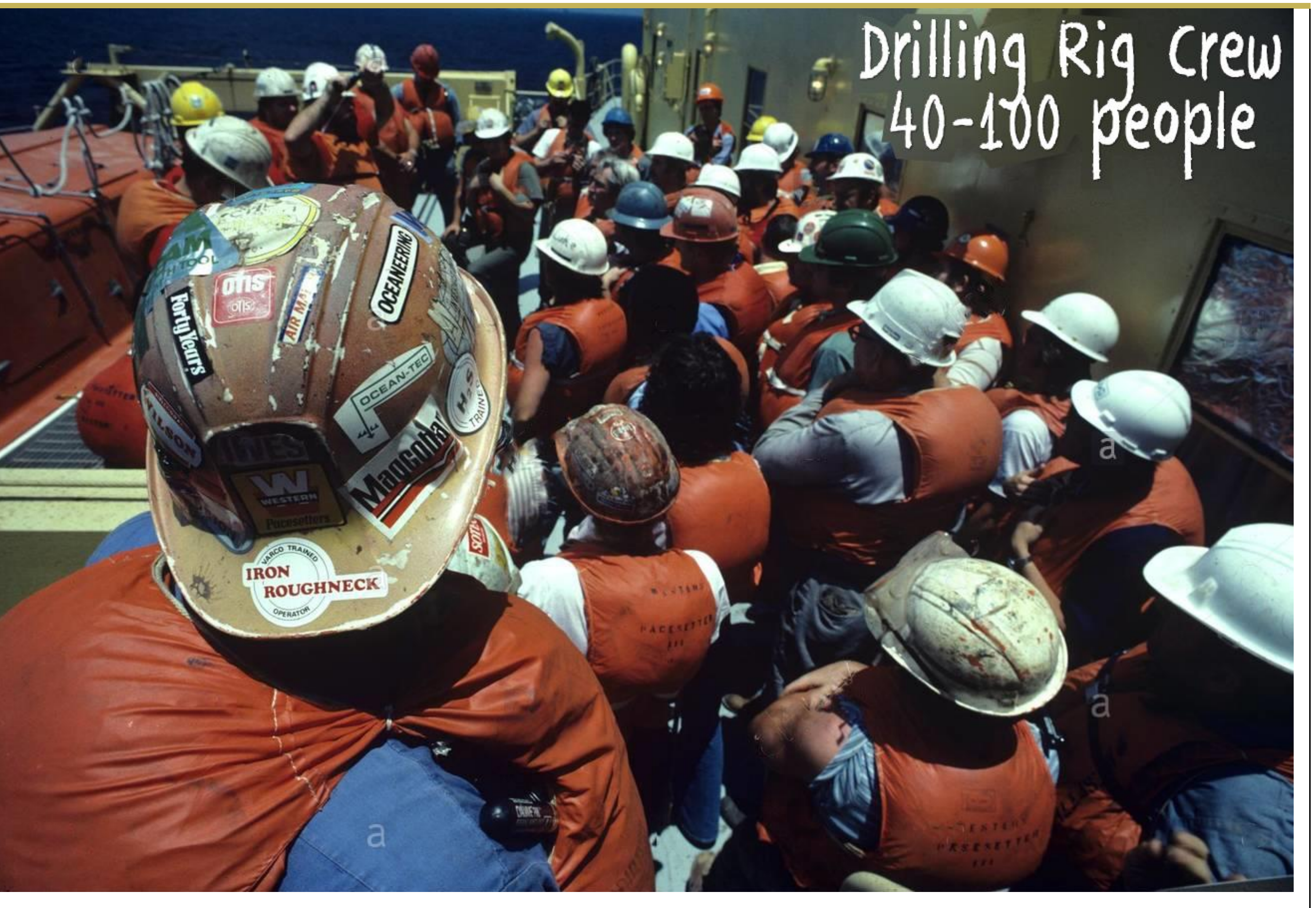
A root cause of high cost is therefore the over specification of the number of people needed for well plug and abandonment because each additional person needs transportation, accommodation and work space.

Possible Mitigation:

Use slickline, wireline or coiled tubing equipment to reduce the number of personnel required. Slickline and wireline crews can be around four (4) people while coiled tubing can be from six (6) to eight (8) people.

The cost savings associated with using slickline, wireline and coiled tubing are significant, whereby proven off-the-shelf equipment can be used with OILtd's enabling method (see Section 7) for Phase 1 and Phase 2 well plugging.

Smaller rig-less jacking crews of six (6) to eight (8) people can be used for Phase 3 well abandonment (see Section E.5).



E.3 Specification of Significant Pipe Handling and Rotary Torque Capability

Root Cause:

As shown to the right, the equipment necessary for efficiently handling pipe and applying rotary torque is significant.

Over specifying the pipe handling and rotary torque requirements for potentially +80% of the well plug and abandonments (P&A) that do not require casing section milling is a root cause of high P&A cost.

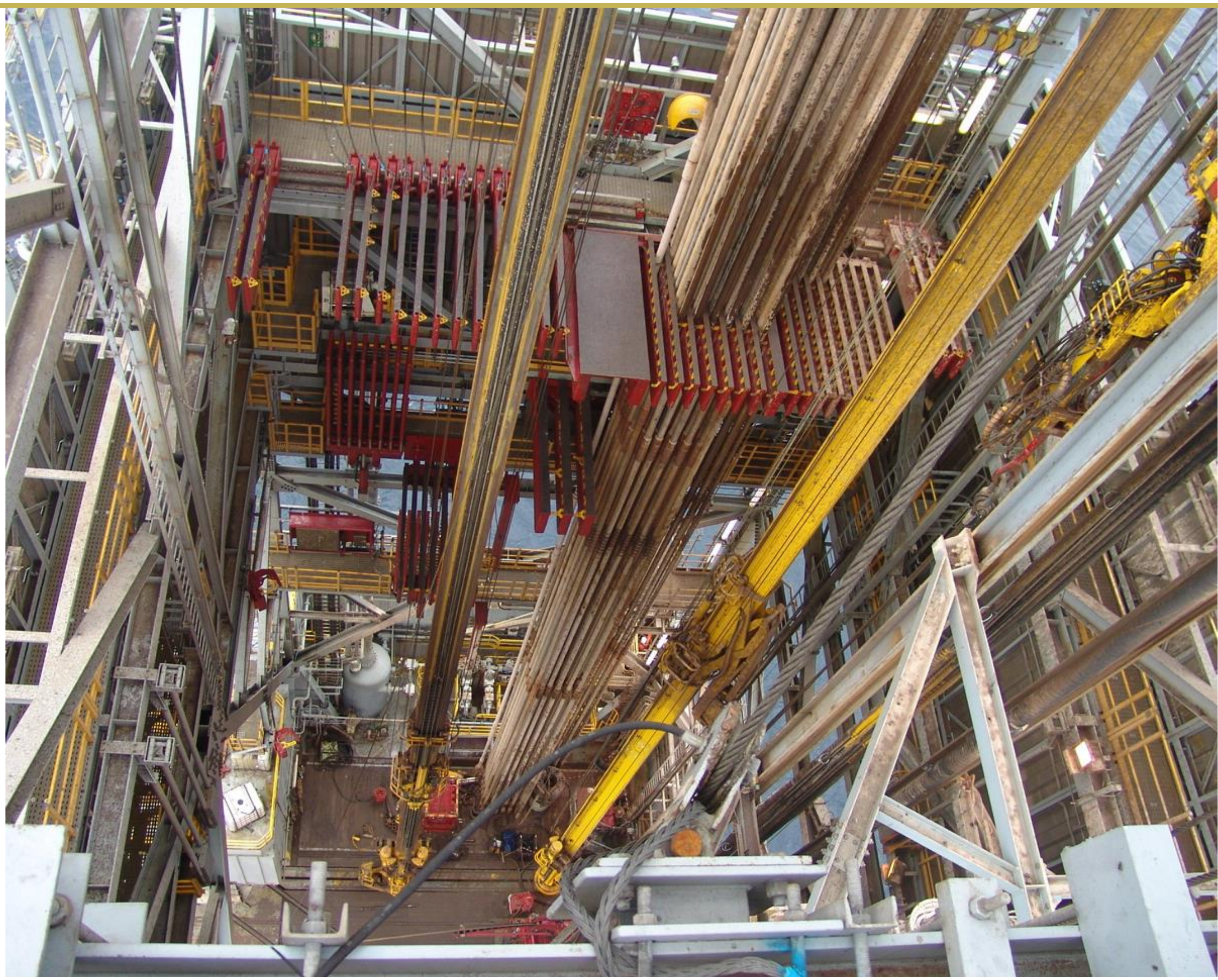
Possible Mitigation:

Avoid using pipe handling equipment until phase 3 surface equipment abandonment where, as described in Section E.5, said pipe handling can be accomplished efficiently using slower jacking mechanisms.

OILtd's enabling method described in Section 7 can be used for Phase 1 and 2 well plugging and does not exclude the use of a drilling rig where it is more efficient for casing section milling operations.

For the 20% of wells that may require casing section milling, a rotary drilling rig or hydraulic workover unit may be used.

Alternatively, casing section milling may be replaced by OILtd's enabling method described in Section C.4.1 and wells having poor or lacking cementation can be plugged according to the requirements (see Section B.1.1).



Rotary drilling rig's derrick and pipe handling looking down onto the rig floor.

E.3.1 Reinstating Decrepit Drilling Facilities Equipment

Root Cause:

As shown to the right, platform drilling rigs may not have been used in many years and are by definition at the end of their useful life.

The cost of reinstating decrepit drilling equipment is high with no return on investment because the platform will be removed after plug and abandonment and, hence, reinstating decrepit drilling facilities is a root cause of high well P&A costs.

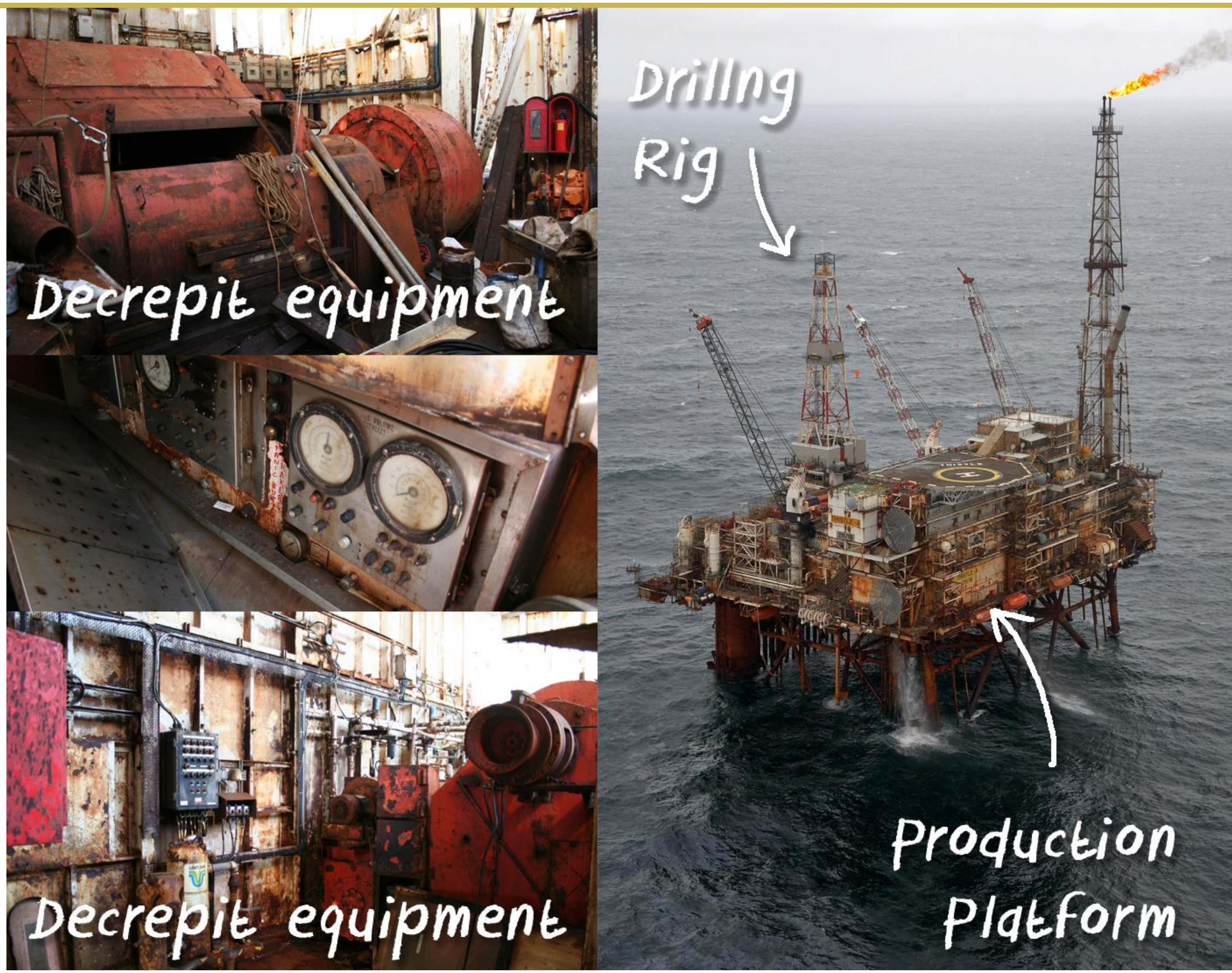
Possible Mitigation:

Avoid re-instating decrepit drilling equipment by using OILtd's enabling method, described in Section 7, for Phase 1 and Phase 2 well plugging, then perform Phase 3 surface equipment abandonment as described in Section E.5 with a slower jacking mechanisms that are more cost effective.

OILtd's enabling method can be used for phase 1 and 2 well plugging and does not exclude the use of a hydraulic workover rig for casing section milling operations.

For the 20% of wells that may require casing section milling, a hydraulic workover unit may be placed upon the platform.

Alternatively, casing section milling may be replaced by OILtd's enabling method described in Section C.4.1 and wells having poor or lacking cementation can be plugged according to the requirements (see Section B.1.1).



Drilling Rigs built into Platforms have typically not been used and require extensive retro-fit for P&A.

E.4 Specification of a Larger Workspace Directly Over Well's bore.

E4 O&G TYPE 3&4 COST DRILLING RIG

Root Cause:

As shown in the picture to the right (also see the picture looking down in Section E.3), an offshore rotary drilling rig has a relatively large workspace directly over the well.

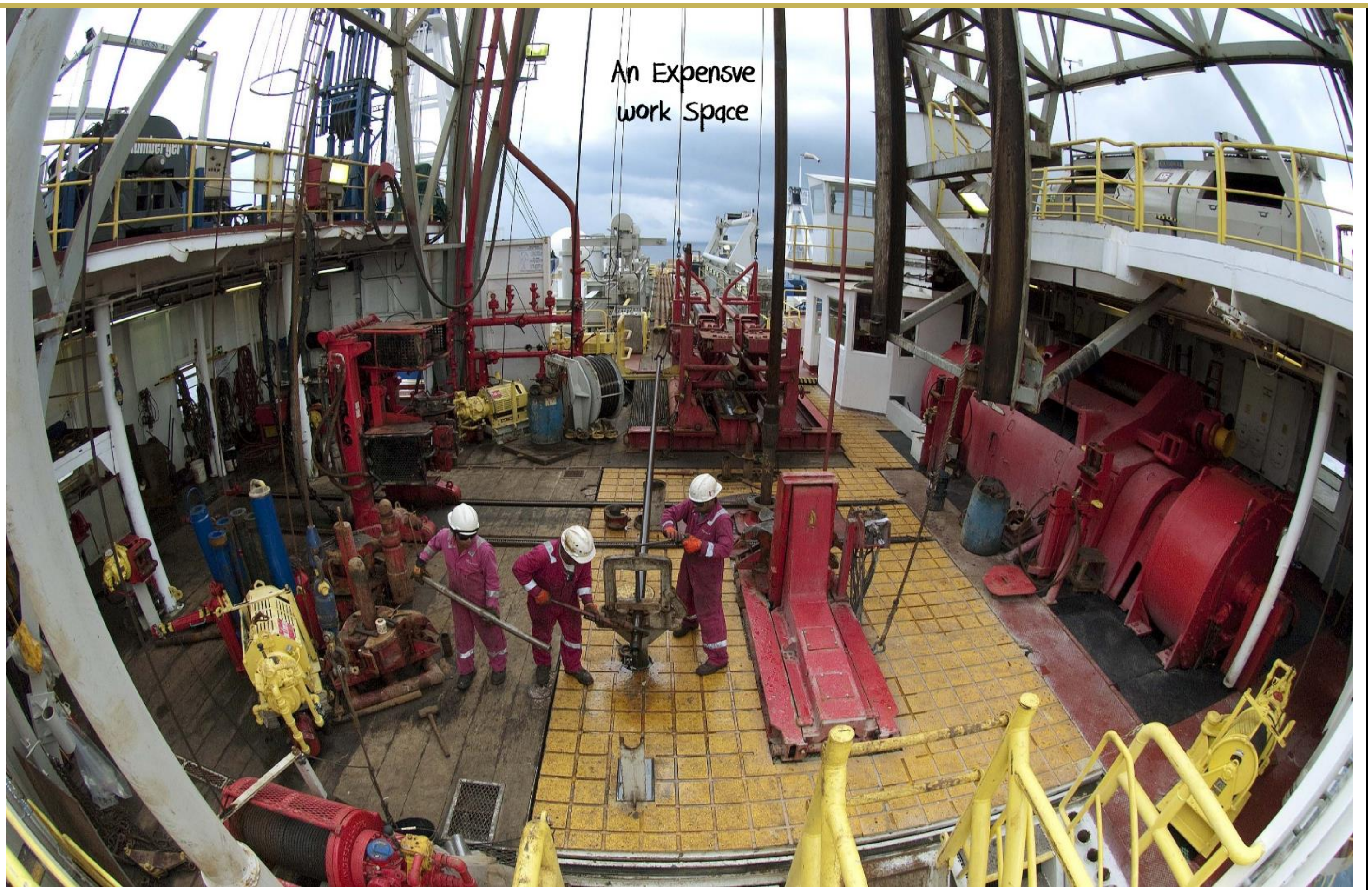
The specification of a large and expensive workspace directly over the well bore's centreline is a root cause of high cost because large and heavy work platforms and equipment must be sited precisely over the well's centre to allow work to be performed and sufficient mitigations must be in place to keep people safe while working over a well that is open to atmosphere (see Section E.1).

O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

Avoid long periods of working directly over the well using slickline, wireline and/or coiled tubing that are rig-up over the well, but where people work at a distance away from the well's centreline.

Use OILtd's enabling method in Section 7 together with mitigations like those shown in Sections E.4.1, E.4.2 and E.4.4, on the following pages, to avoid using the more expensive rotary drilling rig work spaces.



Rotary drilling rig's "drill floor"

E.4.1 Mitigation: Walk-to-Work System

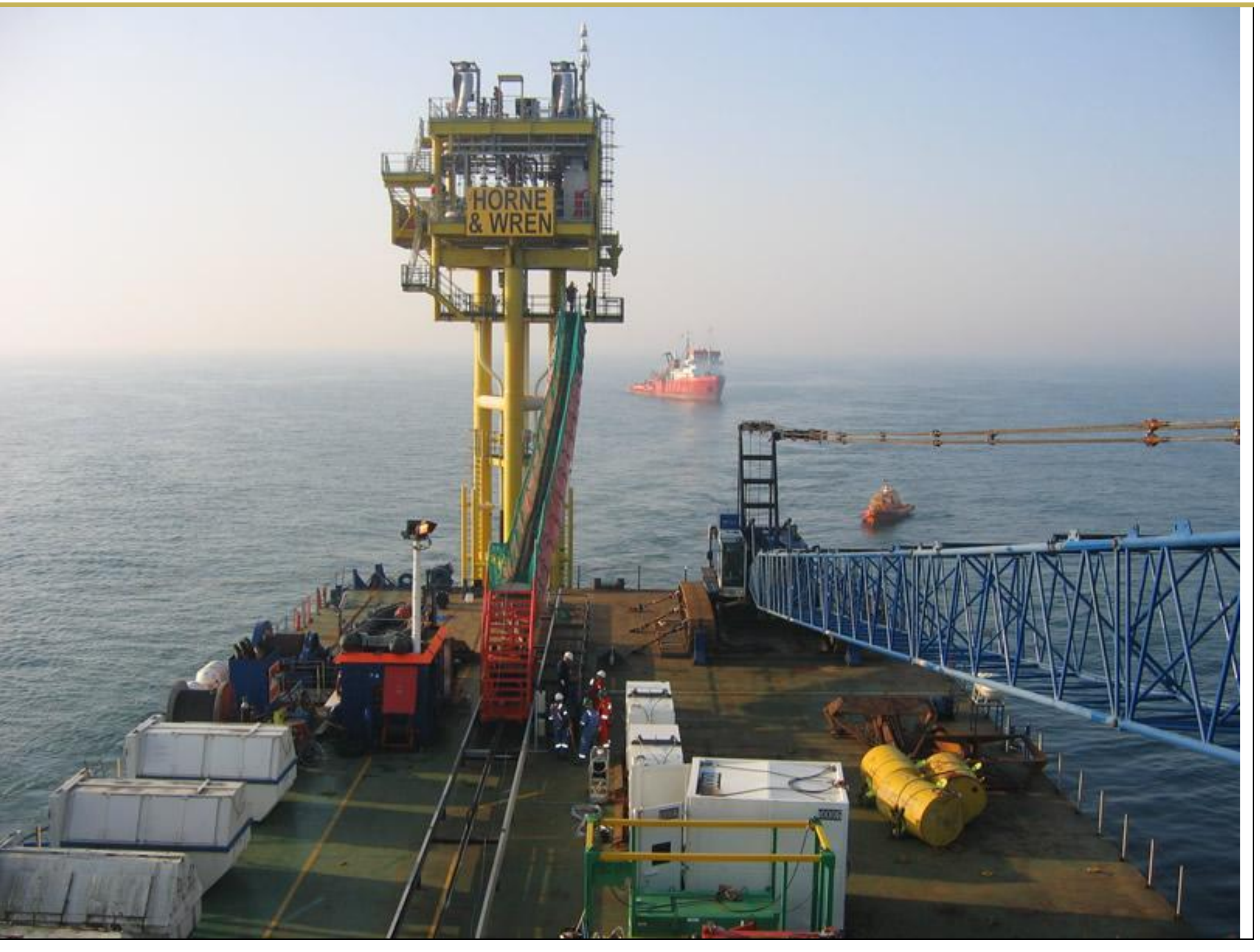
Root Cause:
Insufficient space on the normally unmanned installation (NUI) and/or lack of crane capacity to accommodate lifting and/or operation of equipment.

Possible Mitigation:
As shown to the right, a barge and walk-to-work gangway was used on the Horne & Wren NUI in the UK Southern North Sea.

A crane was placed on the barge for lifting equipment to and from the platform.

For platforms having sufficient deck space for slickline operation and crane capacity, or where a crane can be retrofitted, may use a walk to work system from the back of a supply boat (see in the background to the right) to, thus, remove the need for the barge shown in the foreground of the photo to the right.

Slickline and wireline equipment and operations can be rigged up on most NUIs as shown in Section F.2.7.



E.4.2 Mitigation: Helidecks, Cranes and Supply Boats

Root Cause:

The normally unmanned installation's (NUI's) crane has insufficient capacity to lift all equipment and/or NUI has insufficient space for all equipment.

O&G TYPE 1 COSTS SL & WL

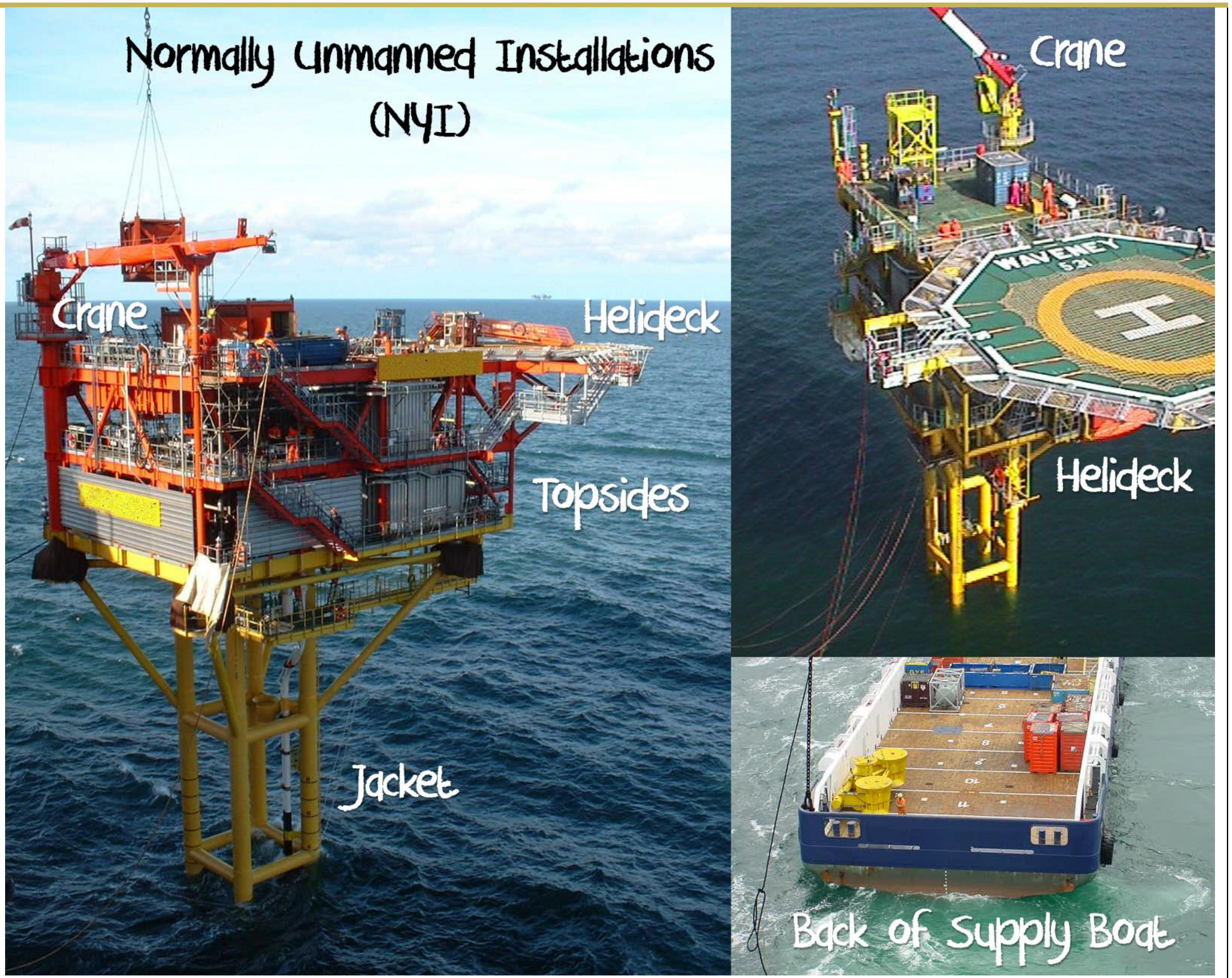
Possible Mitigation:

Helicopter transport can be used where necessary and separate parts of equipment can be lifted from the supply boat using the platform crane and then reassembled on the deck of the installation.

Pumps and other heavy equipment can be placed upon the supply boat with hoses extending to the platform to perform, for example, cementing operations.

Where possible a walk-to-work anchoring system can be retrofitted to the platform and slickline and wireline operational personnel and equipment can be accommodated on the boat to remove the cost and weather issues associated with helicopter flights.

Ultimately, as an Island Nation, capturing valuable UK offshore hydrocarbon assets is better served by training younger slickline and wireline personnel suited to ocean going vessels and working from a supply boat that can be used to reduce the cost of P&A to the lowest possible level so as to reallocate funding to exploration and production.



E.4.3 Mitigation: Jack-Up Barge

Root Cause:

Coiled tubing operations are needed and there is insufficient room or weight capacity on the normally unmanned installation (NUI) or platform.

Possible Mitigation:

Jack-up barges or jack-up boats can be positioned next to the platform and coiled tubing can be spooled from the jack-up barge or jack-up boat with the vessels crane supporting the coiled tubing lift frame (see Section F.2.14).

In some instances, the platform may have sufficient space to place coiled tubing on the deck as shown in Section F.2.16.

Using OILtd's enabling method with coiled tubing can be used to remove the need for a rotary drilling rig and, hence, mitigate the root cause of high plug and abandonment costs.

E.4.4 Mitigation: Subsea Light Well Intervention Vessel

Root Cause:

A subsea well requires plug and abandonment.

Possible Mitigations:

Three alternatives for a subsea well plug and abandonment can be: i) using a drilling rig cantilevered or floating over the top of the subsea well with the well open to atmospheric pressure, which is generally considered to be the most expensive option, ii) using a light well intervention vessel (LWIV) with a subsea lubricator within medium and deep water depths (shown to the right) or iii) suspending the subsea lubricator from the crane of a jack-up boat or jack-up barge like that shown on the previous page in shallow water depths.

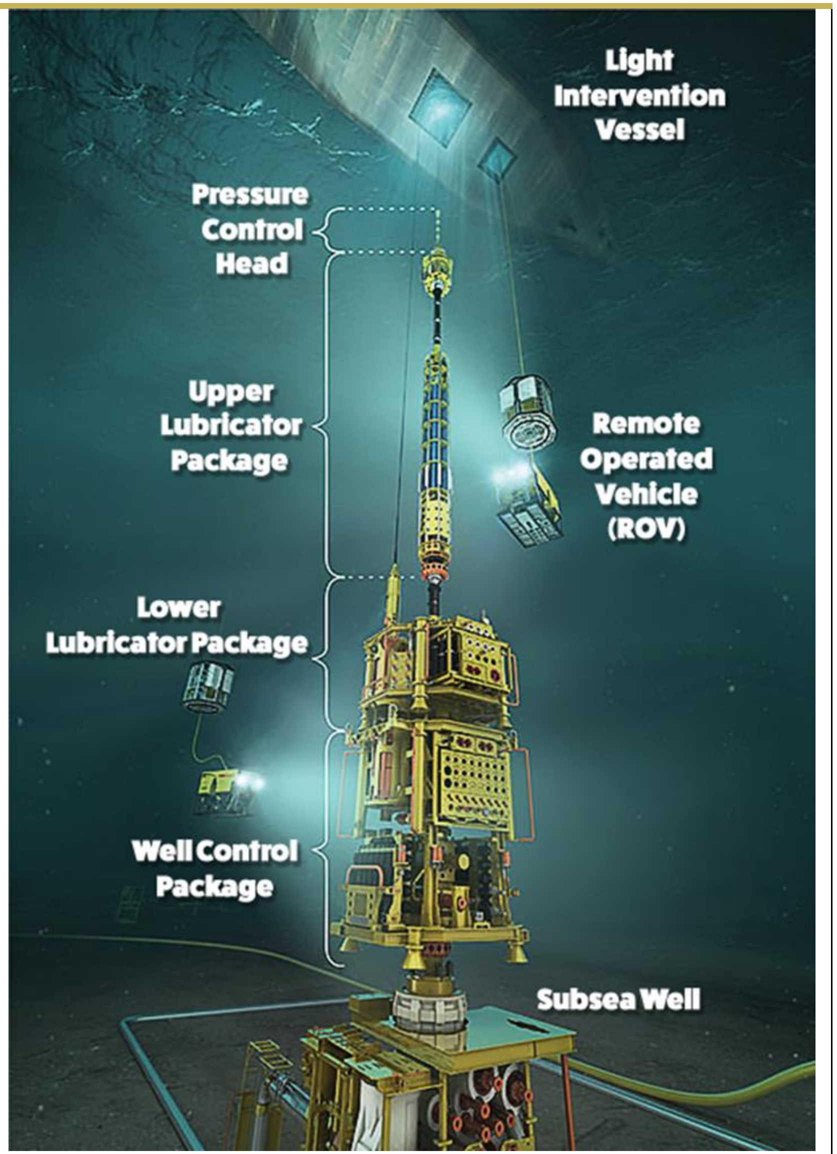
A light intervention vessel, like the one shown to the left, may provide a lower cost than a floating drilling rig, but where the water depth is suitable for a jack-up rotary drilling rig, the cost of the LWIV should be compared to the cost of the jack-up boat or barge with a crane suspending the subsea lubricator system.

Generally, speaking there are no easy options for subsea wells.

OILtd's enabling method, shown in Section 7, is suitable for operations from a barge lifting the subsea lubricator and suitable for use from a light well intervention vessel. It is also suitable for use from a rotary drilling rig to replace, for example, Perf and Wash.

For some subsea wells it may be cost effective to use OILtd's enabling method from a barge or light intervention vessel, or rotary drilling rig, through a subsea lubricator because the method removes the need to open the well to atmospheric pressure through a subsea riser and can be faster to deploy and complete and, hence, reduce the cost of P&A regardless of the vessel being used.

The circumstances of each subsea well may be different, but OILtd's enabling method can be used with any vessel to reduce the necessary time and associated cost of plugging and abandoning a well.



E.4.5 Mitigation: Lower the Cost of Rotary Drilling Rig Operations

Root Cause:

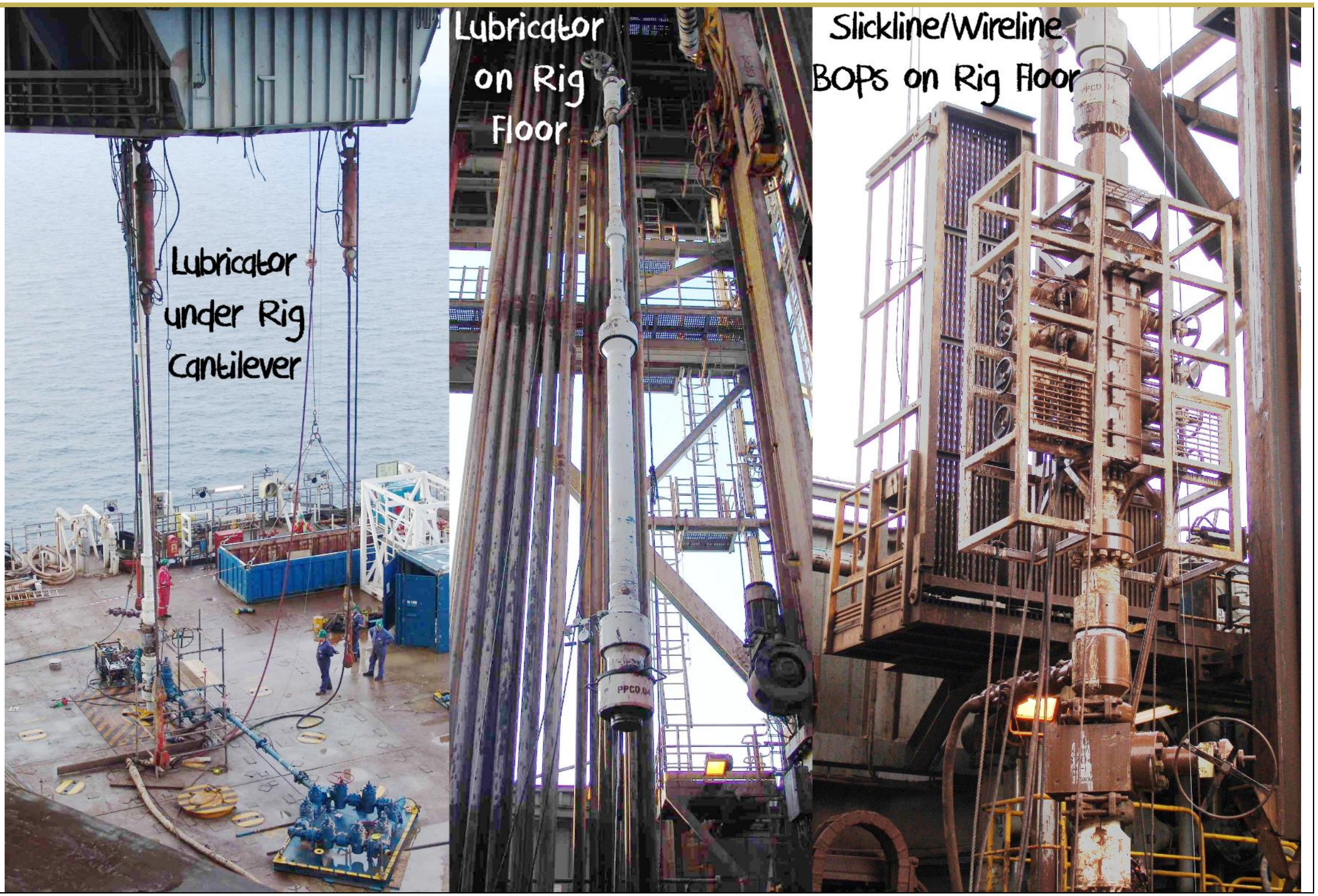
A drilling rig is selected for plug and abandonment.

Possible Mitigations:

Why pull the tubing if you can compact it?

Slickline, Wireline and Coiled Tubing are all used on rotary drilling rigs worldwide every day. If a rotary drilling rig is required, use the slickline, wireline and/or coiled tubing from the drilling rig with OILtd's enabling method, described in Section 7, to reduce the cost of drilling rig well plug and abandonment by removing the need for open atmospheric operations and pulling of the tubing and completion.

Reduce rotary drilling rig non-productive time and the cost of pulling the completion only to run cementing tubulars by compacting the tubing through pressure control equipment.



E.5 Specification of High Speed Heavy Lifting Capabilities

Root Cause: A desire or need for high speed lifting capability exists.

Possible Mitigation: In exactly the same manner as described for compaction (see Section D.1.1), a large cross sectional area of hydraulic jacks can be used to exert a large force, albeit it will not be as fast as the lifting speed of a drilling rig.

To avoid the cost of a drilling rig for the 80% of wells that may not require casing section milling, use OILtd's enabling method described in Section 7 together with rigless abrasive cutting and jacking systems, shown to the right, to preform phase 1, 2 and 3 well plug and abandonment without the use of a drilling rig.

For subsea wells, various off-the-shelf system exist for Phase 3 removal of the wellhead equipment.

F. MITIGATING THE HIGH COST OF WELL ABANDONMENT

Root Cause:

Structure change within the oil and gas industry has moved focus from offshore to onshore fracked wells.

The high cost of well plug and abandonment is creating toxic well portfolios that Operators are not able to sell.

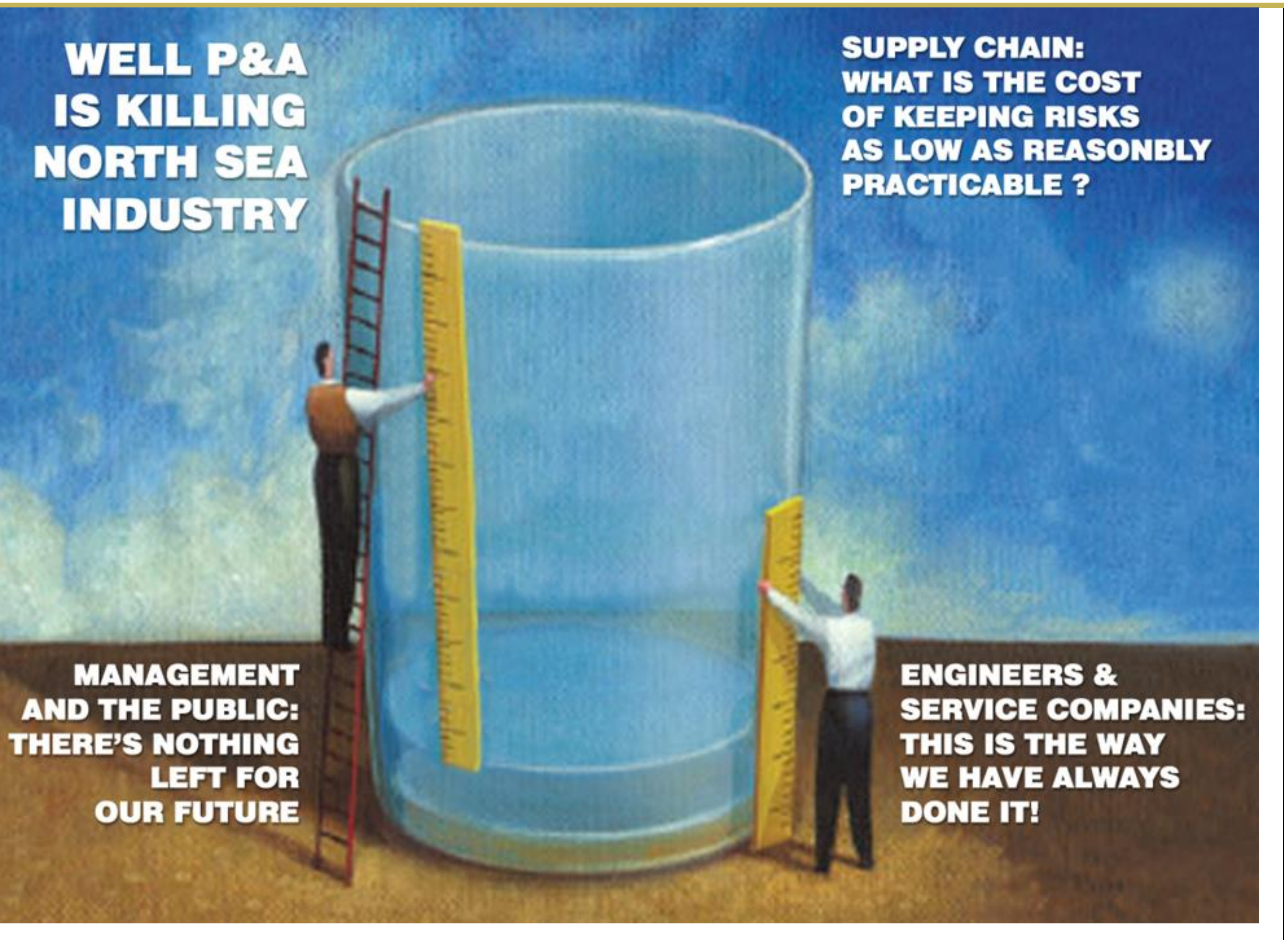
The high cost of well plugging and abandoning is killing the North Sea offshore industry.

Possible Mitigation:

Use OILtd's enabling methods described within this document to create a free market in well plug and abandonment that will deliver the lowest overall well abandonment costs so as to revive the failing North Sea offshore oil and gas industry and allow the sale of older fields to smaller operators.

Open the market for smaller companies with lower overheads to take over aging offshore fields by reducing the cost of well plug and abandonment.

Use drilling rigs to drill new wells. Don't use drilling rigs increase the cost of well plug abandonment to the point of killing the North Sea.



F.1 Early Contractor Involvement

Root Cause:

Contractors hold the competencies to reduce the cost of well plug and abandonment.

Operators and Government hold the budget.

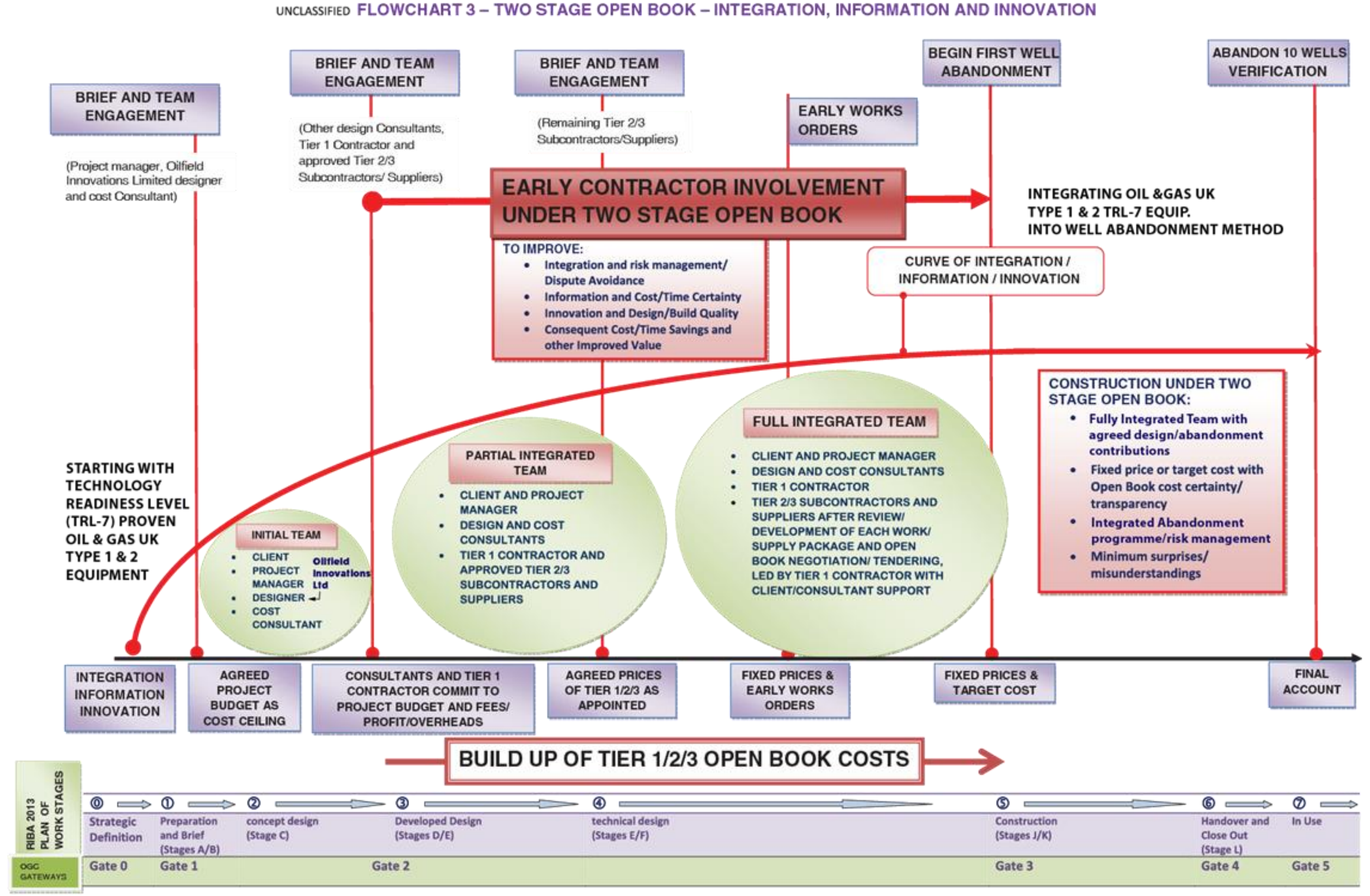
Government, Operators and Contractors not working together to solve the problem is a root cause of high well P&A costs.

ENABLING METHOD COMPATIBLE

Possible Mitigation:

Create a Joint Industry Project (JIP) of Operators, Government and Service Providers who could control and deploy OILtd's enabling methods to create an open market where small service companies can compete successfully against the largest four (4) service companies and drilling contractors to lower the cost off well plug and abandonment so that small operators can continue to take over and operate aging assets.

Use a two stage Open Book approach to develop OILtd's enabling methods together with a menu of frame contracts and price lists to create a free market and allow selection of various service companies to keep smaller companies in business and promote competition.



F.2 Competitive Standardized Off-The-Shelf Tooling

Root Cause:

A root cause of high cost is the lack of competition caused by an oligopolistic service sector who justify their high costs and overheads based upon the cost of using offshore rotary drilling rigs.

Possible Mitigation:

Using standardized off-the-shelf tooling manufactured and deployed by smaller companies within a larger market.

For example, NOV is a recognised and very large equipment provider, but the tools shown to the right are manufactured by many smaller companies and the market is relatively competitive.

Other manufacturers include Thru-Tubing Systems Inc., B&T Oilfield Products, ELM Dynamics, Hunting International, Freddrick's Machine Wirline Tools, Leutert, ect…

OILtd's enabling method shown in Section 7 can use a larger and more competitive market.

These small hand sized tools (see Section D.1.2) have a low lost in hole cost. Where the tools become stuck or left in the well they can be compacted with the tubing to avoid the cost of fishing operations (see Section D.1.5).

F.2.1 Large Standardized Toolbox

Root Cause:

Small slickline or wireline tools are designed for thru-tubing operations and used in Phase 1 reservoir plugging, but are not considered for Phase 2 intermediate well plugging and, hence, the lack of consideration is a root cause of high well P&A costs.

O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

Use the large standardized toolbox of thru-tubing slickline and wireline equipment with OILtd's enabling method described in Section 7 to perform Phase 2 well plugging.

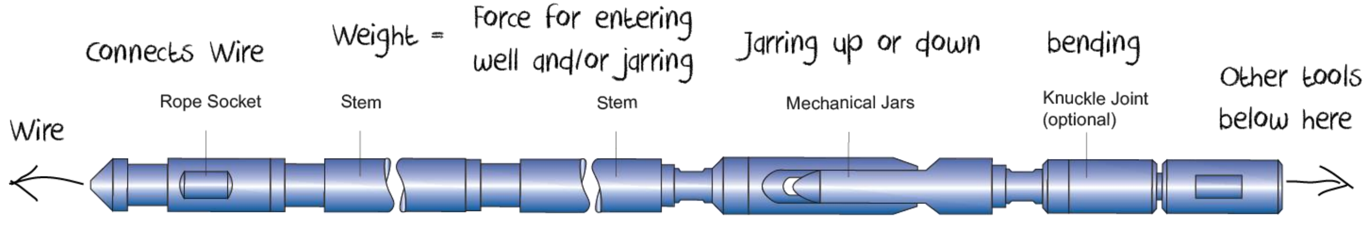
The basic slickline tool string, shown to the upper right, uses a wire rope socket to hoist the tool string into and out of a well.

Stem, or a solid bar of steel, is used to provide weight for gravity to pull the tool string into the well.

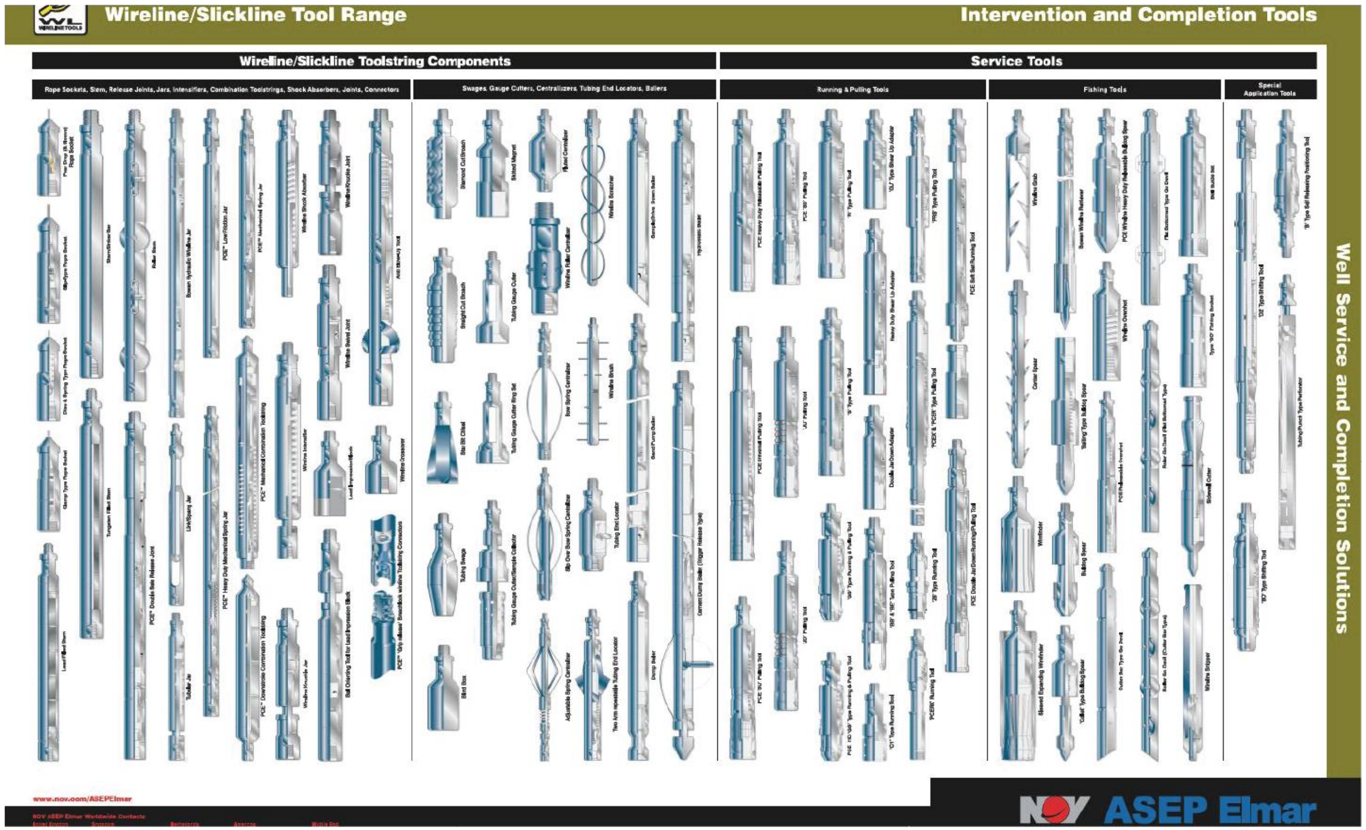
Stem and mechanical jars provide a hammer force to place or remove tools and shear pins to activate springs and/or hydrostatic pressure devices.

An optional knuckle joint can be added to allow bending of the tool string to, for example, pass through or over tubing internal profiles and curvatures.

The various thru tubing tools used for setting mechanical plugs, cleaning tubing surfaces, dumping substances, and other tasks are shown to the lower right and connect to the assembly to the upper right.



Add the below standardized off-the-shelf wireline and slickline tools to the above basic arrangement



F.2.2 Pressure Control Equipment and Lubricator Operations

Root Cause:

Removing the production barriers to allow open atmospheric operations (see E.1) is expensive because many costly mitigation measures are required to ensure safety and environmental protection.

O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

Use a slickline or wireline lubricator arrangement on top of existing production barriers as shown to the right.

A pump in tee and blowout preventers are attached to the existing production tree and the lubricator is attached and detached from the blowout preventers to load and unload tool strings in a pressure controlled environment.

Once the tool string is loaded into the lubricator and the lubricator is attached to the blowout preventers, the preventers and production tree are opened so that the tools can be hoisted and operated within the pressurised well.

Slickline is a solid wire with a smooth surface that a stuffing box can seal around to allow tools to be operated within a pressurized well.

Braided or Electric Wireline use many strands of wire and therefore need a stuffing box that injects grease to maintain a seal around the wire when tools are being hoisted and operated within the well.

A hydraulic or grease injection pressure control system is used to maintain the stuffing box pressure integrity.

The slickline or wireline operator can then control the winch that hoists the tools within the well through existing barriers within the pressurised envelop of the well.

When electric wireline is being used the wireline operator also controls the electrical power and signals passing through the wireline.

Electrically operated mechanisms are used to perform various tasks when electric wireline is used.

Slickline and braided wireline tools are typically operated by using the weight of the tool string as a hammer that sets or removes mechanical devices and/or shears pins to use spring activation of a tool function.

The proposed method of vertical cutting of tubulars for compaction (see Section 7) can use slickline or braided wire to lift and lower cutting wheels (see F.2.9 and F.2.10) or electric wireline to operator a perforator (see F.2.11).

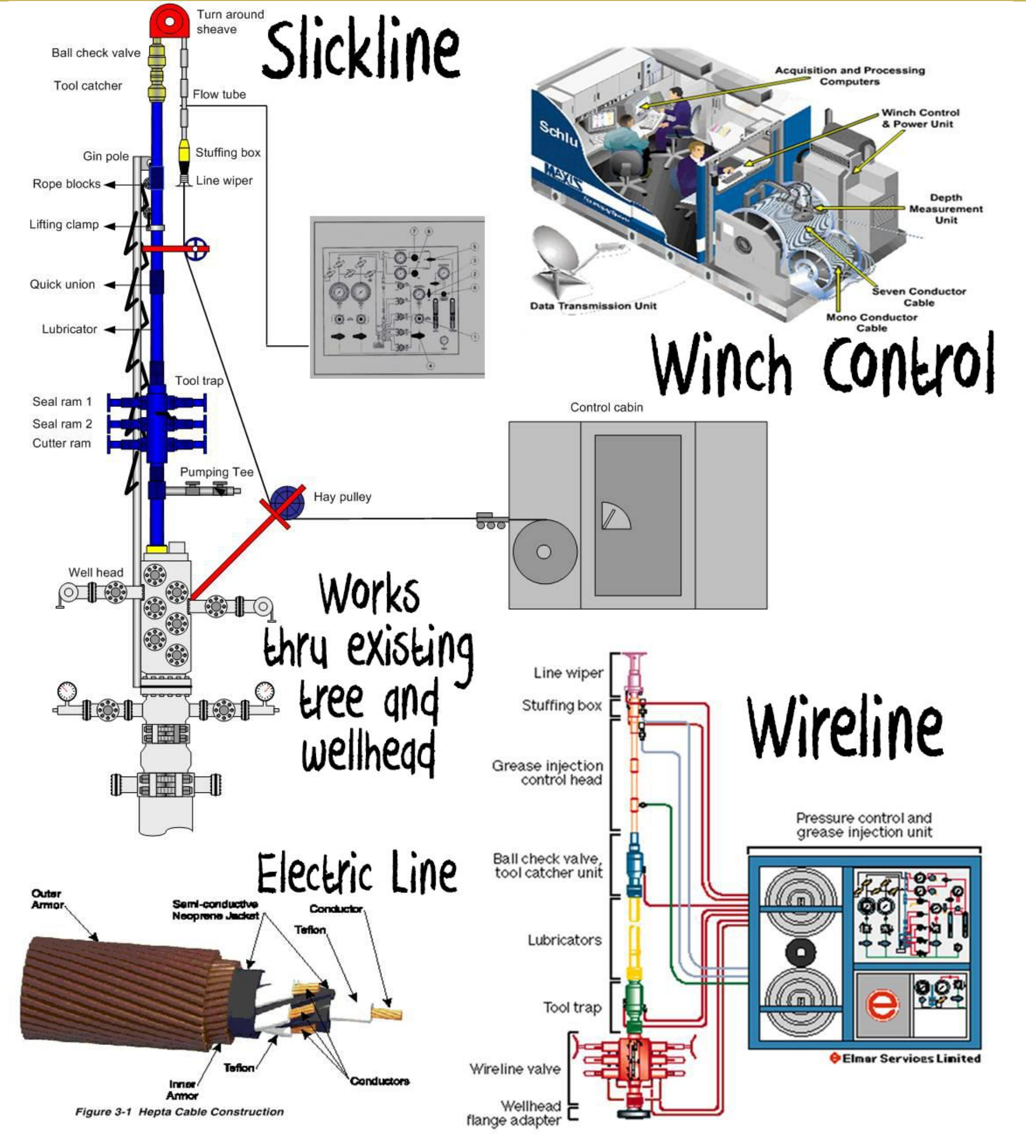


Figure 3-1 Hepta Cable Construction

F.2.3 Slickline and Wireline Rig-up

Root Cause:

Replacing the primary mechanical production tree barrier, shown to the right, with a fluid barrier (see Section D.2) for open atmospheric operations (see E.1) is expensive because many costly mitigation measures are necessary to ensure safety and environmental protection.

Possible Mitigation:

O&G TYPE 1 COSTS SL & WL

Use OILtd's thru-tubing enabling method and slickline or wireline Blowout Preventer (BOP), a lubricator and a stuffing box on top of the existing production tree.

Primary well control temporarily is shifted from the production tree to the stuffing box which seals around the slickline or wireline shown to the right.

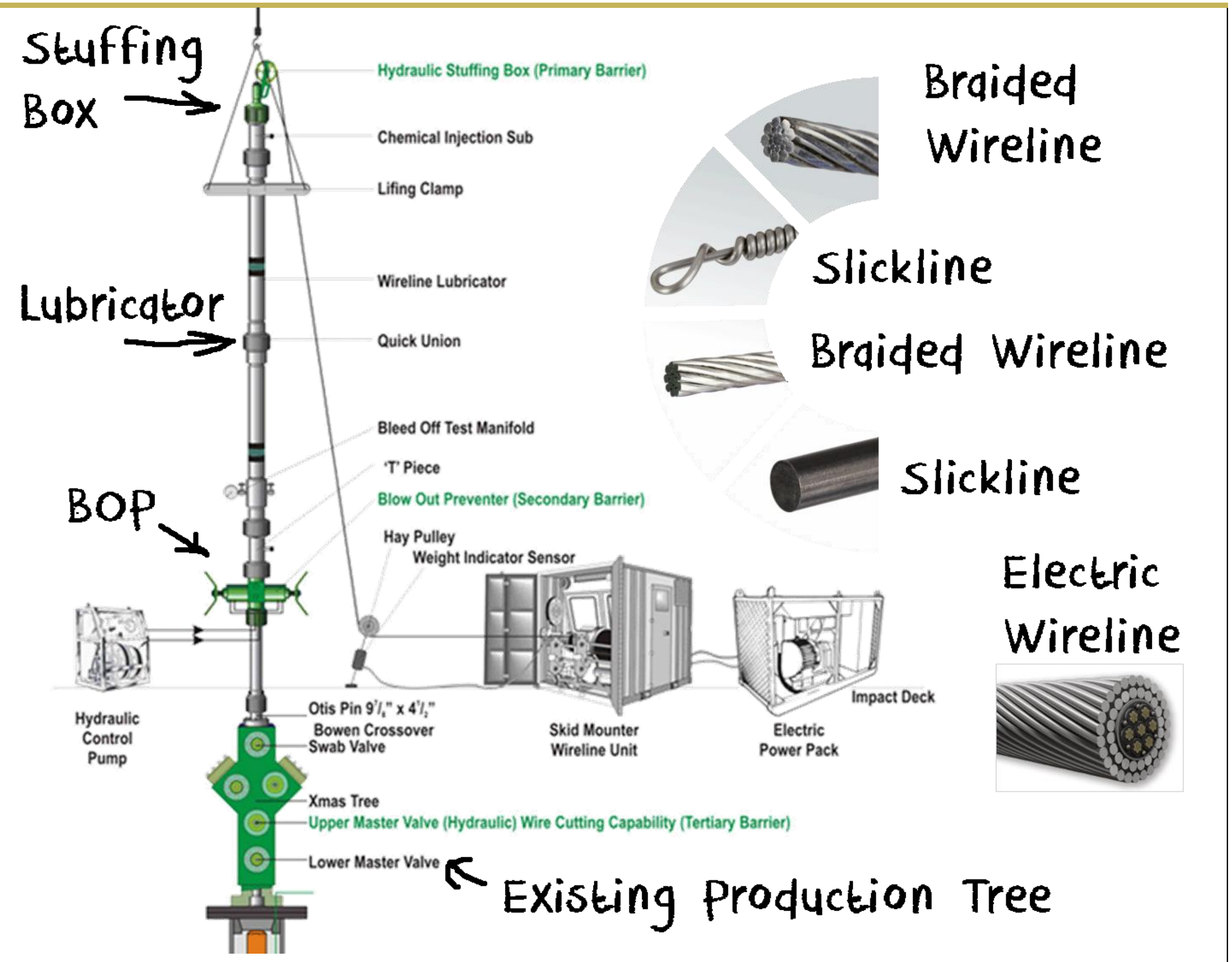
The secondary barrier during thru-tubing operations is the BOPs.

If the existing production tree is capable of shearing the wire, it becomes the tertiary barrier during thru-tubing operations.

Wireline Tools are loaded into the lubricator before it is attached to the BOPs, when the production tree and BOP valves are closed.

Once the lubricator assembly has been tested, the BOP and production tree valves are opened and wire is feed through the stuffing box to hoist tools through the production tubing.

The costs associated with open atmospheric operations are avoided.



F.2.4 Size of Pressure Control Equipment

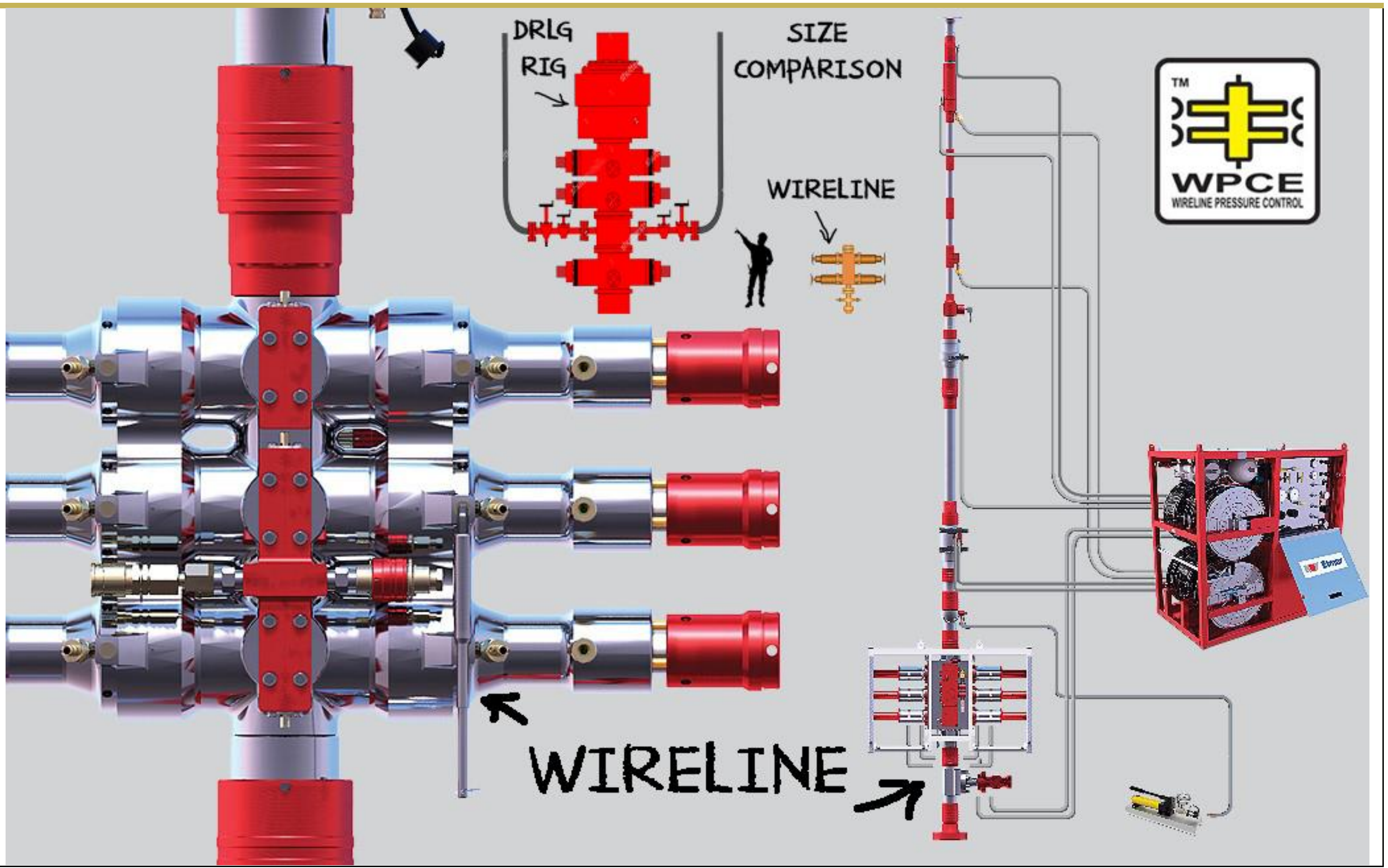
Root Cause:

Pulling the tubing and completion requires a large blowout preventer internal diameter. The cost associated with using a large diameter blowout preventer is high and, thus, a root cause of high well P&A costs.

Possible Mitigation:

Use OILtd's enabling method, described in Section 7, to compact tubing so that the internal diameter of the blowout preventers is relatively small.

Standardized slickline, wireline or coiled tubing Blowout Preventers (BOP) and associated equipment can be used with thru-tubing operations to reduce the size of equipment and the associated cost of workspace and accommodation in an offshore environment.



F.2.5 Costs Associated with Well Inclination

Root Cause:

Oil and gas wells may have high inclinations and/or be horizontal.

A Drilling Rig may be selected based upon well inclination and, thus, inclination may be a root cost of high well P&A costs.

Possible Mitigation:

Typically gravity deployed slickline and wireline work in wells up to 45 degrees in inclination and friction reducing devices may be used to work within well inclinations of up to 60 degrees.

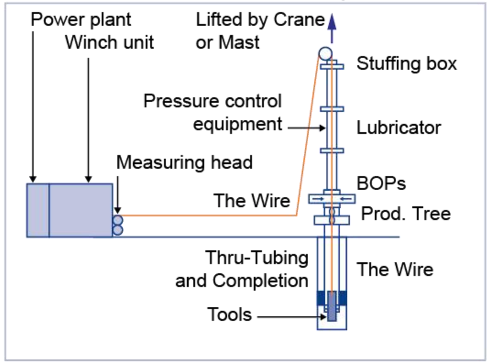
OILtd's enabling method described in Section 7 can use slickline and wireline in up to 60 degrees inclined wells, otherwise coiled tubing and/or electric wireline and a tractor is needed to enter well inclinations above 60 degrees.

Well plug and abandonment does not generally require entering long horizontal sections of the well since these sections are below the sealing cap rock (see Section B.1.1).

Accordingly, Phase 1 plugging of the reservoir can use slickline or wireline with or without a tractor and are typically used to prepare wells for drilling rig open atmospheric pressure operations.

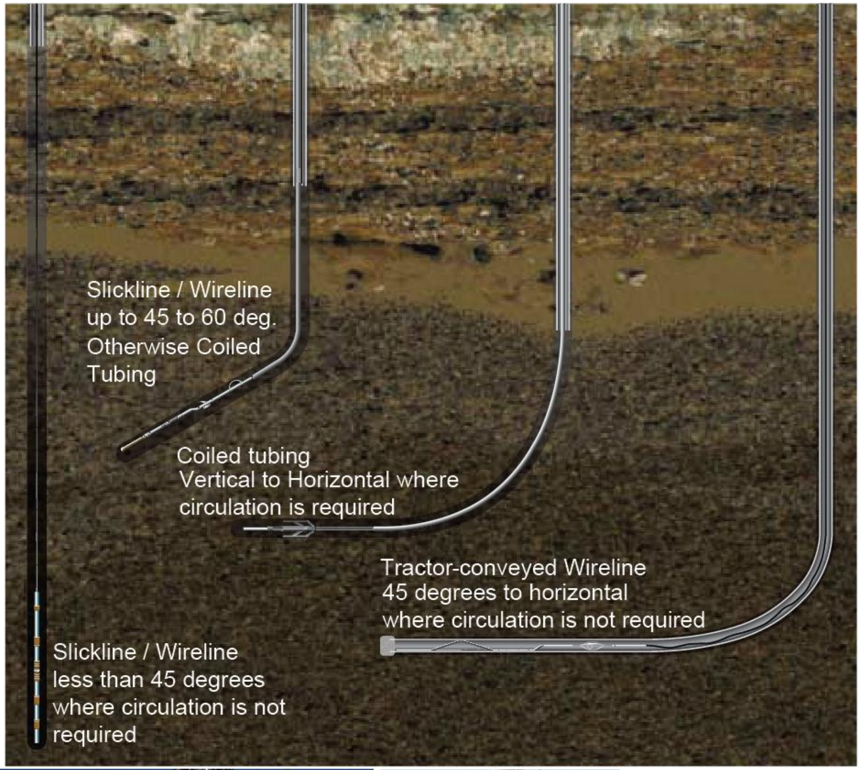
The inclination of Phase 2 plugging will generally be less than 60 degrees for most wells.

Slickline / Wireline Rig-UP



Slickline / Wireline Operator's Panel

Well bore inclinations associated with Slickline, Wireline and Coilted Tubing



F.2.6 Slickline or Wireline Footprint

Root Cause:

Pulling the tubing and completion equipment from the well requires a large lifting capacity and work space, which is a root cause of high well P&A Cost.

Possible Mitigation:

Use slickline or wireline with OILtd's enabling method described in Section 7 to remove the need to pull tubing.

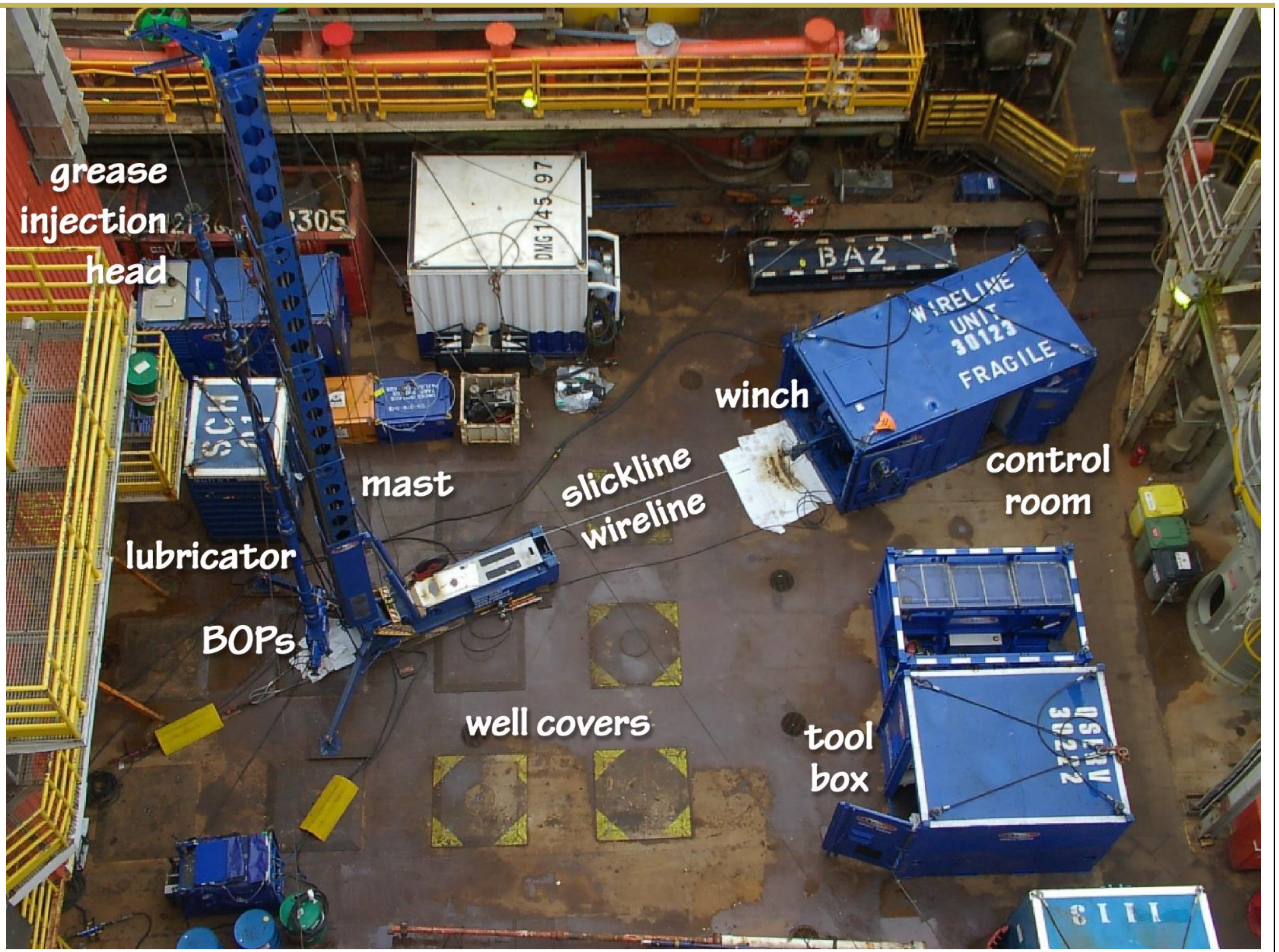
The equipment necessary for OILtd's enabling method Phase 1 and 2 well plug and abandonment on a manned offshore platform is shown to the right.

The blue wireline unit shown in the upper right has a control room and slickline or wireline winch.

Slickline or wireline passes through pulleys and the mast shown to the left before entering the grease head used to seal around the slickline or wireline.

The lubricator on the left is connected and disconnected from the BOPs to allow loading and unloading of tool strings from the lubricator while the well is closed in at the BOPs and production tree using a swab valve or work valve on top of the production tree.

The equipment is relatively light, mobile and has a small foot print, whereby the mast can be replaced by, e.g., a crane.



Blue pieces of slickline/wireline equipment can be used to replace a drilling rig P&A

F.2.7 Slickline or Wireline on NUI

Root Cause:

People believe that the space provided by a drilling rig is necessary for normally unmanned installation (NUI) well plugging.

Possible Mitigation:

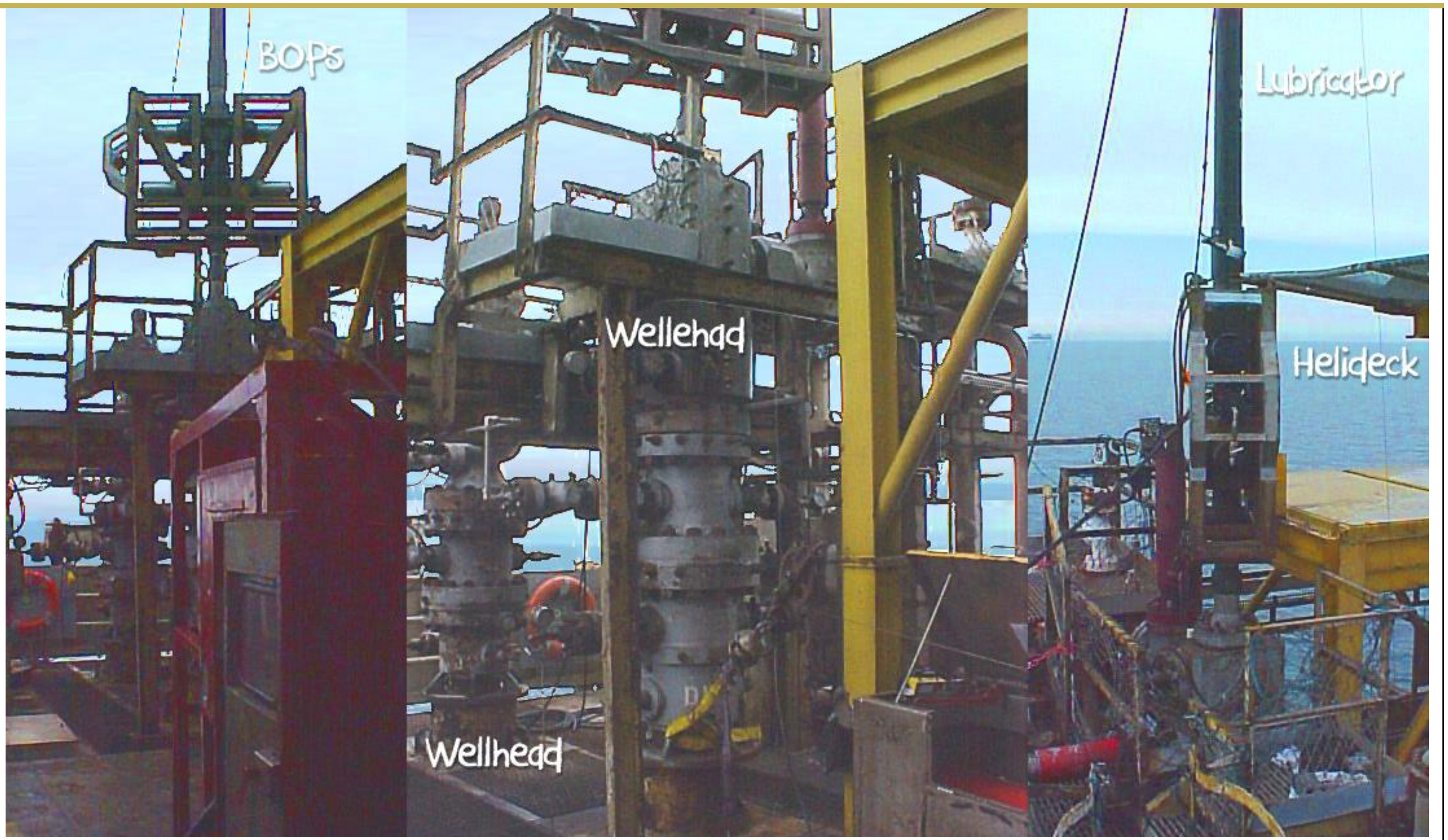
As shown to the right, slickline and wireline can be used on relatively small NUI's.

The picture to the right shows the slickline blowout preventers (BOPs) rigged up on top of the wellhead and production tree.

The lubricator is picked up and laid down on the helideck when tools are loaded and unloaded.

The control winch is painted red and shown on the left where the door is visible.

Accordingly, OILtd's enabling method described in Section 7 can be used on normally unmanned platforms to mitigate the high cost of drilling rig well plug and abandonment offshore.



Slickline rig-up on a small Normally Unmanned Installation (NUI)

F.2.8 Conventional Tubing Severance

Root Cause:

A false belief exists, whereby it is believed that drilling rigs cut tubing and/or completion components, when milling is typically the only drilling rig form of cutting tubulars.

During drilling rig P&A, slickline and/or wireline tools are typically used to cut tubing and completion components and, hence, the misconception that drilling rigs can effectively perform thru-tubing operations is a root cause of high P&A costs.

Possible Mitigation:

Use the same means of cutting tubing and completions components that are currently used from a drilling rig without paying for an over specified drilling rig to provide work space and accommodation.

As shown to the right, knife, wheel or chemical cutters are typically used for tubing severance.

The slickline or wireline off-the-shelf cutting tools shown to the right can be used with OILtd's enabling method, described in Section 7, to reduce the cost of well plug and abandonment.

Alternatively, to further lower the cost of using OILtd's enabling method for well plugging, it is possible to vertically split the tubing at coupling connections so that the tubing can be separated at the coupling and severance can be avoided.

Splitting the tubing body at the coupling so as to part the tubular string at the coupling can also be carried out using explosive split shot or the vertical cutter shown at the bottom of the next page.

F.2.9 Conventional Hangers compared to Low Cost OILtd Vertical Cutter Design

Root Cause:

OILtd's enabling method described in Section 7 is a new way of using off-the-shelf equipment. Off-the-shelf equipment can be more expensive than OILtd's purposely designed tooling.

Possible Mitigation:

A purposely designed deployment means for proven plumber's pipe cutting wheels (See Section F.2.10 on next page) uses a skate arrangement similar to conventional gauge hangers.

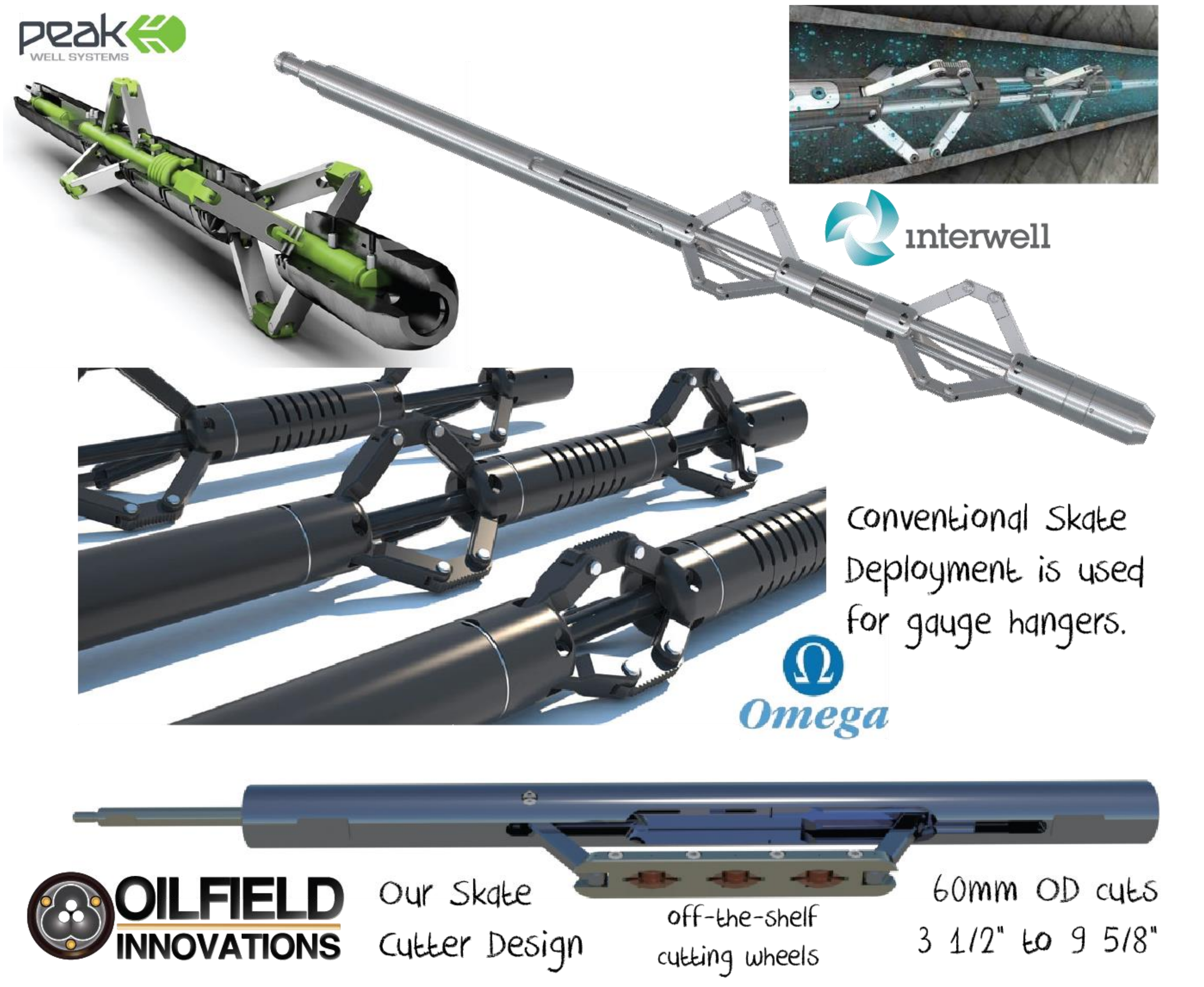
The purposely designed 60mm diameter tool is sized to vertically cut tubular sizes from 3 ½" OD tubulars to 9 5/8" OD tubulars.

Conventional hydrostatic actuators can be used to extend and retract the skates carrying the cutting wheels, which are rolled up and down with hoisting of the slickline assembly.

Our hand sized vertical cutter has a low cost design that can be manufactured relatively easily and refurbished on site.

An alternative off-the-shelf vertical perforator (see Section F.2.11) can also be used with electric wireline to operator a tractor and cutting knife

The skate cutter to the lower right is designed to be a low cost cutting tool with simple parts that can be disassembled, maintained and reassembled at the well site.



F.2.10 Low Cost Off-the-Shelf Cutting Wheels

Root Cause:

Oil & Gas downhole knife, chemical and explosive tubing cutters can be expensive.

Possible Mitigation:

Plumbers and pipe fitters have used cutting wheels for a long time.

The off-the-shelf cutting wheels from the right were purchased from a local hardware shop and used to cut the OCTG L80 5 ½" – 20-ppf tubular shown.

These low cost off-the-shelf cutters can be deployed with a skate (see Section F.2.9) that can be extended, retracted and hoisted up and down within a tubular to vertically split it and carry out OILtd's enabling method described in Section 7.

These low cost off-the-shelf cutting wheels can also be used with a number of phased vertical cutting skates to shred a tubular in OILtd's enabling method described in Section C.4.1.

Vertically splitting or shredding long sections of tubing or casing for compaction or cement repair can use multiple slickline or wireline trips into and out of a well to allow changing of the cutting wheels.

The hub of the cutting wheel can be painted so that the slickline or wireline operators can visually confirm the downhole wall has been cut completely when the paint on the hub has become worn or removed.

F.2.11 Gator Perforator for Vertical Weakening

Root Cause:

Tool development can be expensive.

Despite the potential for a large return on investment in developing, for example, a vertical cutter (see bottom right illustration in Section F.2.9) or qualifying a new enabling method (see Section 7), Operators are not skilled in tool or method development and avoid being the first to use any new tooling or methods (See section A.1 Blame Culture).

Possible Mitigation:

Qualify OILtd's enabling method described in using all proven off-the-shelf equipment Section 7 and then work with qualified service companies to develop lower cost tooling so as to avoid the inflated costs of conventional oil and gas proprietary equipment and means.

OILtd's enabling method described in Section 7 can be carried out with technology readiness level 7 (TRL-7) off-the-shelf field proven tooling.

A Gator Perforator, shown to the right, can be adjusted to weaken the tubing sufficiently to simulate vertical splitting or shredding of the tubing so that it may be compacted to provide an unobstructed space for through tubing logging and cement plugs.

The Gator Perforator is operated on electric wireline using a tractor to pull the knife shaped punching tool along the tubing.

The Gator Perforator knife is extended to punch the tubing, after which it is retracted. Once retracted the tractor moves the tool a specified distance, the process of punching is repeated.

By adjusting the distance the tractor moves the tool, the tubing can in effect be split or shredded.

Off-the-Shelf Tractor Driven Punch Capable of Vertical Splitting

F.2.12 Off-the-Shelf Inflatable Packers

Root Cause:

The tubing internal diameter is too small for effective drilling rig operations so the cost of using a drilling rig to pull the tubing is incurred.

Possible Mitigation:

Compact the tubing with an inflatable piston instead of pulling it.

Through tubing inflatable packers are proven off-the-shelf technology.

Typically, as shown in the bottom left of the right hand graphic, radial stays or slips are attached to a material similar to a car's tyre to prevent movement of the inflatable packer after it has been inflated.

Inflatable packers are sometimes accidently pumped down hole if the stays or slips cannot withstand pressure applied against the top of the inflatable packer.

OILtd's enabling method (see Section 7) can use an inflatable packer as a piston and, as shown in B.4.1, stays that are not intended to hold the inflatable piston packer can be used to clean the casing during compaction.

F.2.13 Coiled Tubing Overview

Root Cause:

Fluid circulation cleaning of the well bore to provide a water wettable surface necessary for a permanent cement plug (see Section B.1.1) prompts drilling engineers to carry out expensive casing section milling (see Section C.4) with a drilling rig.

Possible Mitigation:

Use OILtd's enabling method described in Section C.4.1 to shred the casing and use OILtd's enabling method of C.4.2 with coiled tubing circulation to vibrate and clean behind the casing so as to embed the shredded casing strands, like rebar reinforcement, within the cement plug.

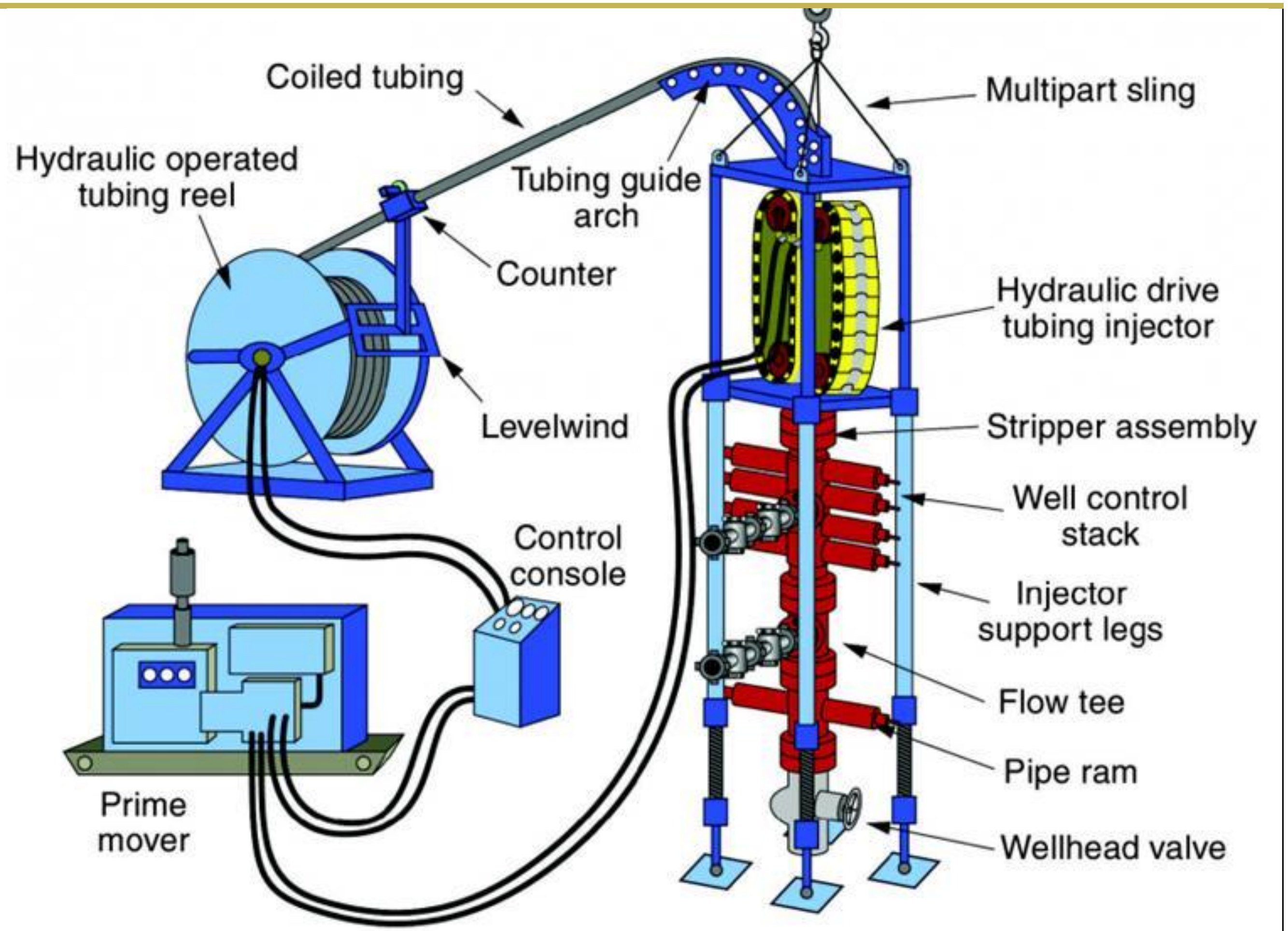
As shown to the right a prime mover and control console operate a hydraulic real of coiled tubing.

The coiled tubing is pushed and pulled into and from the well using an injector, whereby the stripper assembly forms a seal around the smooth outer diameter of the coiled tubing to provide a primary barrier.

The coiled tubing blowout preventers (BOPs) and pipe rams provide a secondary barrier.

Coiled tubing can be rigged up on the existing production tree and provide thru-tubing operations within a pressure controlled environment to avoid the high cost of open atmospheric drilling rig operations (See Section C.3).

A full range of off-the-shelf coiled tubing equipment and tooling are readily available.



F.2.14 Coiled Tubing Relative Size or Scale

Root Cause:

Circulation is required to clean and perform well plugging.

People are unaware, untrained or uncomfortable with lower cost alternatives and select higher cost options.

Possible Mitigation:

As shown to the right, coiled tubing arrangements can fit on the back of a lorry.

A personnel cabin can control the reel of coiled tubing, which passes through the tubing guide arch and hydraulic tubing injector.

The hydraulic tubing injector pushes the coiled tubing through the stripper which forms a seal around the coiled tubing to avoid opening the well to atmospheric pressure.

Blowout Preventers (BOPs) provide a secondary barrier for thru tubing operations.

Alternatively, methods not requiring circulation as described in Section B.3.1, B.3.2, B.3.3 and B.4.1 may be used.

F.2.15 Coiled Tubing Footprint

Root Cause:

Circulation is required to clean and perform well plugging.

People are unaware, untrained or uncomfortable with lower cost alternatives and select higher cost options.

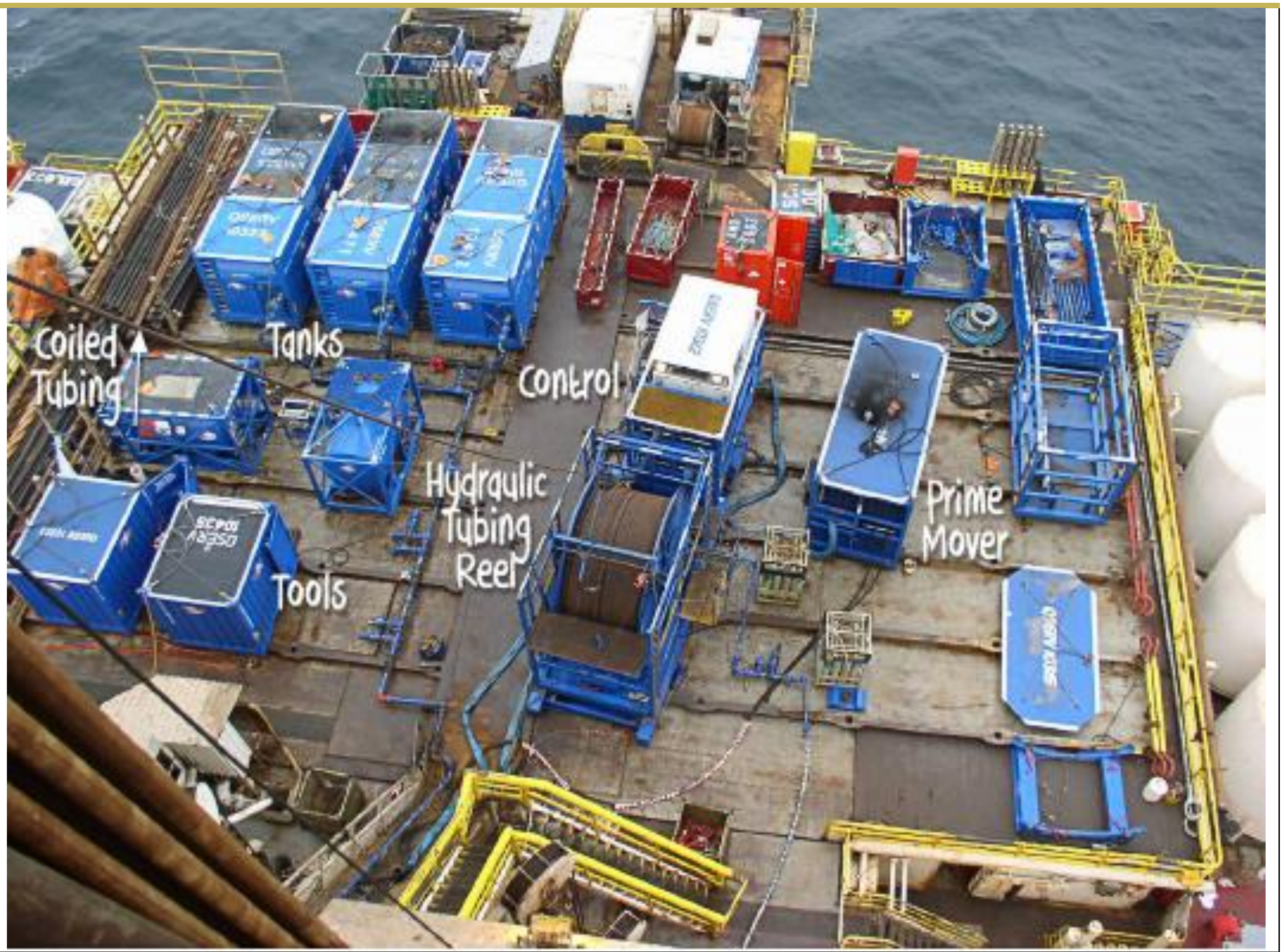
Possible Mitigation:

The blue coloured equipment shown to the right is associated with a coiled tubing operation. The equipment has been placed upon the platform deck and is used to perform thru-tubing operations. See Sections F.2.13 and F.2.14 for additional views.

Coiled tubing can be used to perform OILtd's enabling method described in Section 7 where circulation is required.

Additionally, as an alternative to section milling or Perf and Wash, coiled tubing can be used with OILtd's enabling method described in Section C.4.1 to shred the casing and use OILtd's enabling method of C.4.2 with coiled tubing circulation to vibrate and clean behind the casing so as to embed the shredded casing strands like rebar reinforcement of the cement plug.

Alternatively, methods could be used that not require circulation as described in Section B.3.1, B.3.2, B.3.3 and B.4.1.



F.2.16 Coiled Tubing on NUI

Root Cause:

Circulation is required during well plugging and the platform and a normally unmanned installation (NUI) has limited space.

Possible Mitigation:

The diameter of the coil can be minimised to limit the size of the coiled tubing reel and associated equipment.

Additionally, the length of coiled tubing may be minimised by using the coiled only during phase 2 well plugging of the intermediate sections by using slickline and wireline methods during phase 1 reservoir abandonment.

For example, phase 1 plugging of the reservoir could use methods not requiring circulation as described in Section B.3.1, B.3.2, B.3.3 and B.4.1 could be used.

As shown to the right, a coiled tubing rig-up has be put into a very limited space to avoid the need for a more expensive drilling rig solution.

G. INCREASE VESSEL COMPETITION

Root Cause:

The offshore platform or normally unmanned installation (NUI) has limited space for slickline, wireline or coiled tubing operations and the drilling rig market is expensive.

Possible Mitigation:

Use a jack-up boat or jack-up barge from the available market and include windfarm vessels to create more competition and, thus, lower the cost of providing work space and accommodation offshore.

As shown to the right some jack-up boats are self-propelled and have a crane capable of supporting operations on a minimalistic NUI platform.

Normal offshore workers can be used when a jack-up facility is placed next to an NUI and a bridge gangway is used.

H. CROSS TRAIN WELL INTERVENTION PERSONNEL

Root Cause:

Fracking has changed the structure of the oil and gas industry and offshore oil and gas, faced with an aging work force and huge well P&A liability, must reduce costs to remain competitive with onshore oil and gas fracking operations.

A root cause of poor offshore economics can be the high cost of well P&A.

O&G TYPE 1 COSTS SL & WL

Possible Mitigation:

Because slickline and wireline is by conventional definition the lowest cost well intervention (see Section 4), the lowest possible cost well plug and abandonment would use a walk-to-work system with a supply boat that would carry pumping equipment and serve as an accommodation.

Because the offshore industry is not accustomed to accommodating workers on a boat, younger professionals who are capable of living on a supply boat at sea would need to be trained in well plugging operations.

Sailors could be recruited and trained in the use of wireline and slickline to reduce the cost of well plugging and abandonment to an absolute minimum.

Such professionals would not necessarily be confined to plug and abandonment and could also be used for well intervention optimisation.

Supply boat with walk-to-work system to a normally unmanned platform (NUI) where crane and temporarily mast are used for slickline and/or wireline operations.

I. PATENTED AND PATENT PENDING ENABLING METHODS

Enabling methods shown in Sections 7, B.3.1, B.3.2, B.3.3, B.4.1, C.4.1 and C.4.2 are patented and patent pending technologies controlled 100% by Oilfield Innovations Limited, whereby Oilfield Innovations are willing to trade control interest of said methods for widespread use in exchange for a typical oil and gas 1/4 working interest for 1/3 development funding arrangement and/or a royalty per use arrangement with Governments, Operators and/or Service Providers.

Interested Parties may contact Oilfield Innovations via the information found on www.oilfieldinnovations.com