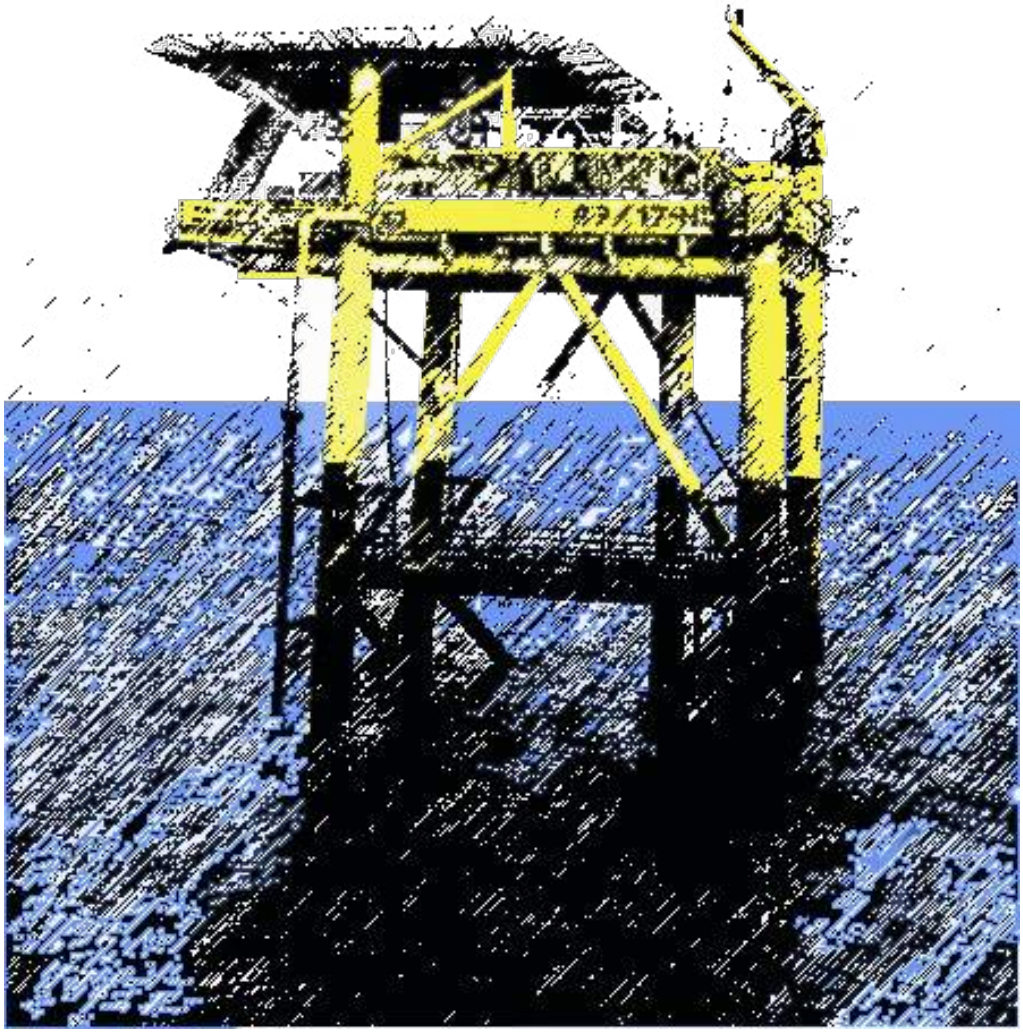
Prospectus

Universally Compliant Method of Rigless Well Plug and Abandonment



OILFIELD INNOVATIONS

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Prospectus for Universally Compliant Rigless Well Plug and Abandonment Method

by Clint Smith[a] and Bruce Tunget[b]

Abstract: The social cost of offshore well plug and abandonment (P&A) is extreme and could escalate by 150% to 354% (Boschee, 2014)[15]. "UK taxpayers are facing a £24 billion bill for decommissioning that threatens to wipe out the remaining value of UK North Sea oil and gas (Ward, Financial Times, 2017)[1]." About 47% of decommissioning costs are well plug and abandonment (Thornton, 2017)[8], so over £11 billion is attributable to well P&A. Well P&A is, literally, putting cement into a hole-in-the-ground, so why is it so expensive? The majority of that £11 billion cost is not for cement plugging of the wells but, instead, relates to the systematic selection of the most expensive, instead of the least expensive, offshore logistics. This fact is easily demonstrated by comparing relatively inexpensive "onshore P&A" to very expensive "offshore P&A," for similar well architectures. Many industry proven offshore logistical alternatives exist; however, industry systematically selects the most expensive offshore logistical means for well P&A. Proponents of drilling rigs, which account for 40% to 70% of construction and P&A costs (Canny, 2017)[17], cite cement bond measurements and keeping risks as-low-as-reasonably-practical (ALARP); however, measuring the cement bond is regularly avoided during drilling rig P&A and quantitative risk assessment shows that lower cost well logistics, using fewer people protected by pressure containment systems, are safer (Håheim, 2003)[9]. To explain this conundrum to those financially authorising drilling rig P&A requires ordinary speech to avoid the confusing technical jargon of practitioners. With those terms of reference in mind, Oilfield Innovations Limited, a Scottish registered micro-company, seeks funding to qualify a safer and lower cost universal rigless P&A method that uses lower cost industry proven tooling and offshore production intervention logistics, combinable with the logistics of other decommissioning activities, to reduce P&A cost by 32% (Siems, 2016)[21] to 60% (Varne, 2017)[85] and put cement into a hole-in-the-ground according to present regulatory requirements and industry best practice so as to keep risks and legal liabilities as-low-as-reasonably-practicable.

Introduction

Many corporations and governments around the world are feeling the effects of revenue tax deductions associated with offshore tax expense.

Offshore may no longer be the most attractive play, as World Oil reported in March 2017, "Exxon Mobile is diverting about one-third of its drilling budget this year to (onshore) shale fields that will deliver cash flow in as little as three years, said Chairman and CEO Darren Woods"[131].

In January this year, the Financial Times[1] reported "UK taxpayers are facing a £24bn bill for decommissioning oil and gas fields in the North Sea, which threatens to wipe out remaining tax revenues from an industry that has been among the Treasury's most reliable cash cows for the past four decades."

A few weeks ago, BP's Vice President of Decommissioning (Thornton, 2017)[8] reported to the International Oil and Gas Producers (IOGP) well experts committee that 47%, over £11 billion, of that cost is well plug and abandonment (P&A).

BP also alluded to the prospect that the estimated £11 billion P&A cost (47%) could increase by the historic decommissioning cost escalation rate of 150% to 354% (Boschee, 2014)[15], i.e. £16.5 billion to £1.25 trillion.

In the authors' experience, it is quite common for a rig-based P&A cost estimate to increase by factors of 150% to 350% once work begins and the unpredictable internal condition of older well becomes evident during P&A.

Offshore P&A has the two (2) objectives of: i) putting at least two cement plugs into a hole-in-the-ground, and then ii) removing the above seabed well equipment, wherein the cost of accomplishing these two simple objectives for +/- 5,000 UK wells is over £11 billion or £2.2 million per well.

If you ask external or resident P&A "experts" why it costs so much? You will get a lot of unnecessary technical jargon that leaves you even more confused.

We agree with Einstein who said: "if you cannot explain a problem simply, you do not understand it well enough."

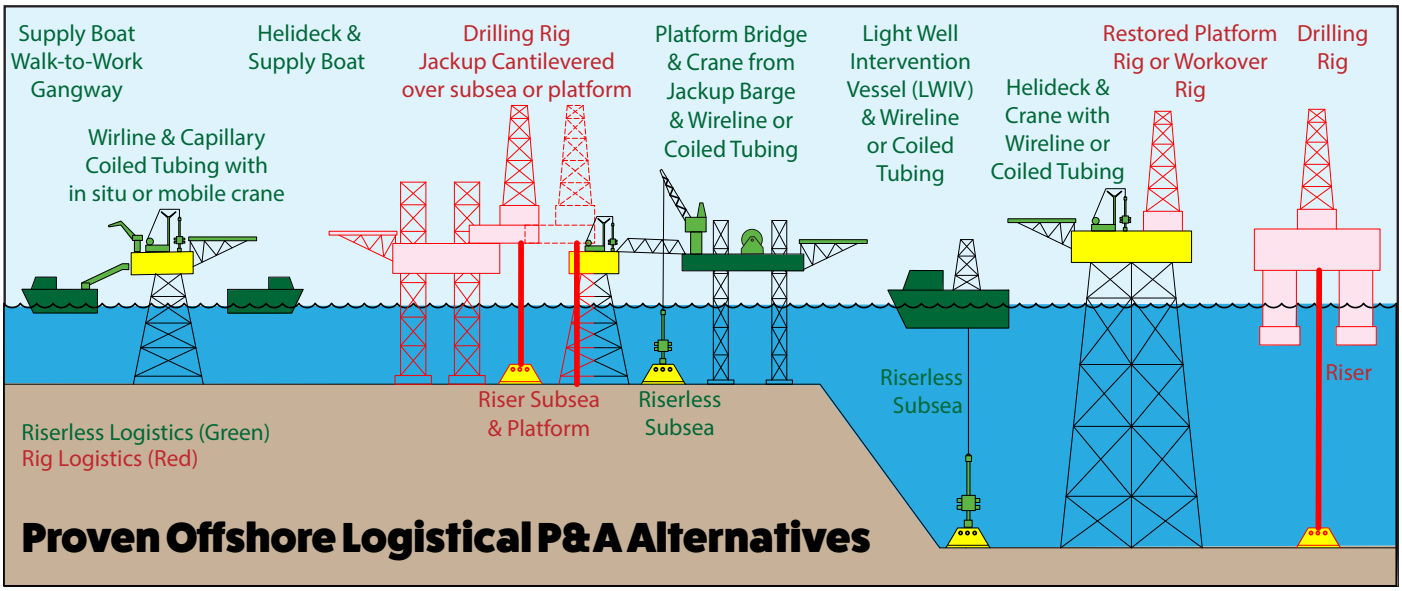

Figure 1 - Proven Offshore Logistical P&A Alternatives

What Drives Offshore P&A Cost

Plug and abandonment of "onshore" wells is relatively simple and low cost because you can drive up to the well with a truck mounted rig to quickly remove the tubing, place cement and cut off the near ground level production equipment at the top of the well (wellhead).

Conversely, "offshore" logistics are costly, time consuming and require traversing a vast and often hostile ocean environment, whereby companies are responsible for providing an inhabitable and safe working environment.

It is, in fact, "logistics" that drives the majority of the £11 billion cost of UK P&A and, unfortunately, arguments between P&A "experts" as to the need for rig or rigless P&A work-scopes (see Figure 5) is at the heart of systematic selection of the most expensive logistical alternative of drilling rig P&A.

A step change in offshore P&A cost requires significantly reducing offshore logistical costs, which means drilling rig logistics must be replaced by rigless P&A logistics combined with other decommissioning activities and/or traditional rigless well intervention logistics.

Using the various Figure 1 "rigless" logistical methods, experts within a combined decommissioning campaign of 176 of 360 well P&A's and 92 of 109 structure removals, produced cost savings of 32% over more conventional methods used in the Gulf of Mexico (Siems, 2016)[21].

Arguably, if more of the 360 wells had been riglessly plugged and abandoned, more than 32% savings could have been achieved given that drilling rig cost accounts for 40% to 70% of well construction and deconstruction expense (Canny, 2017)[17].

For example, an ENI study, showed that the ease of operations and light weight equipment of a rigless light well intervention vessel (LWIV) provided a 50% cost savings (Karlsen, 2014)[22], while more recent studies indicate 60% cost savings (Varne, 2017)[85].

A 30% to 60% P&A cost savings of between £3.3 and £6.6 billion, before escalation, would result in average per well P&A cost savings of £660,000 to £1,320,000 across the £11 billion total cost for the UK's +/- 5,000 wells.

Combining P&A with other decommissioning logistics requires rig-less P&A equipment whereby, for example, if qualifying Oilfield Innovations' rigless P&A method to API 17N technology readiness level 7 (TRL-7) cost a £1 million, the capital investment would be returned within the first two well plug and abandonments.

A step change in UK P&A costs that returns billions to the Treasury can be achieved by riglessly delivering a rig-based P&A work scope and combining the logistics of rigless P&A with other decommissioning activities.

Different Experts may be Needed

Drilling rig logistics are relatively easy. An oil and gas company contracts a drilling rig contractor who mobilises a self-sufficient drilling unit, refurbishes an owned platform drilling rig or mobilises a workover rig onto a platform and together with existing contracts the company is, more or less, ready for P&A.

Almost everyone but the UK Treasury and taxpayers, who will need to make up the tax shortfall, are happy with the status quo.

Combining decommissioning and rigless P&A logistics will obviously cause consternation and anxiety within the industry, especially within Operator drilling departments.

How could saving billions in UK P&A costs be anything other than controversial when said savings will adversely affect peoples' lives and jobs?

Conversely, many more peoples' lives will be adversely affected when decommissioning wipes out the tax revenues from UK oil and gas and forces government austerity measures.

Keeping the status quo may be obviously easier but, according to the Financial Times, it may be the end of UK North Sea oil and gas tax revenues.

Accordingly, if external or resident P&A experts resist changing P&A practices, for the good of the United Kingdom, different experts may be needed.

Rig versus Rigless Logistics

For reference, Figures 2 shows the enormous size of a typical UK Southern North Sea (SNS) rig compared to a UK SNS platform. Figure 3 shows a similarly sized platform with a walk-to-work gangway from a floating vessel and Figure 4 shows a jack-up barge and bridge link to the same platform during the UK Horne Wren decommisioning[48].

Figure 2 - LeTourneau 116C Class Drilling Rig over a Small Platform in UK Southern North Sea

Based upon the size alone, you do not need to be a rocket scientist to see that the rig-based logistical costs of Figure 2 will be significantly greater than the rigless logistical costs of Figures 3 and 4.

The equipment on drilling rigs is designed for harsh "drilling" environments. Through Operator revenue P&A deductions, Tax Payers are paying for 100% of the rigs "drilling" equipment when only about 25% of the equipment is necessary for P&A.

Rigless P&A logistics require detailed planning to determine available workspace, well access, lifting needs, pumping capacity and other rigless logistical requirements for various service and equipment contracts before P&A can be combined with other decommissioning activities.

Unfortunately, Oil and Gas Operators do not presently allocate sufficient resources or time to carry out anything other than a status quo [rig-based] plug and abandonment (Jenkins, 2016)[13].

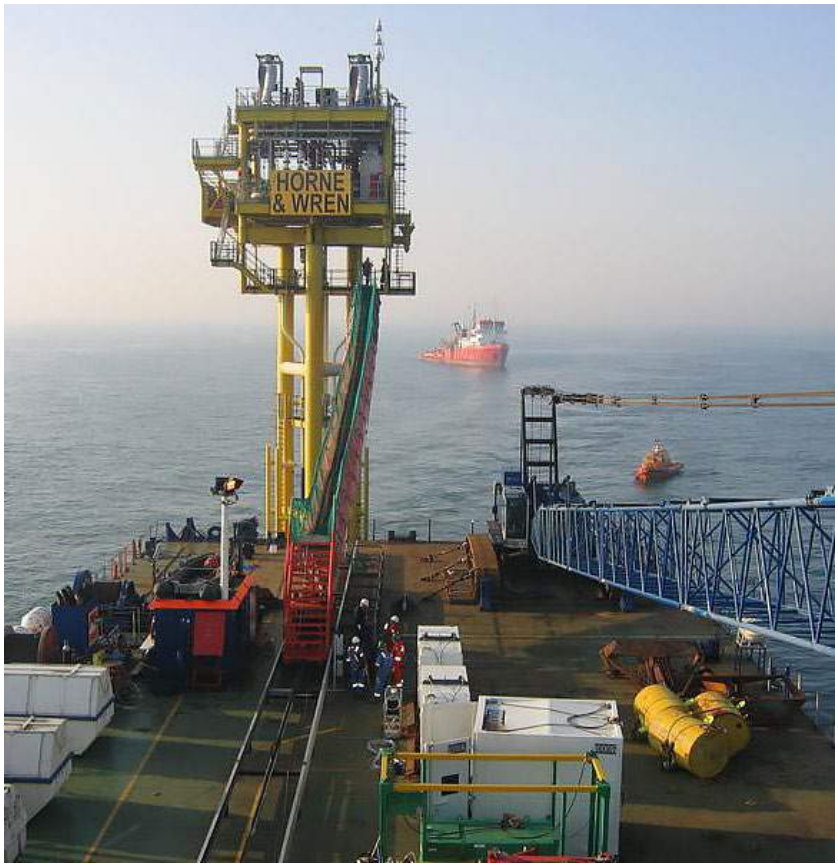

Figure 3 - Walk to Work System Horne Wren[48] (Decom World)

Figure 4 - Barge Bridge Linked to UK SNS Horne Wren Platform (Tullow)[48]

While more front-end staff for rigless intervention engineering will be required, logistical and contracting services can be included within other decommissioning activities to minimise cost.

Figure 1 shows the various offshore logistical options that can be used. Small platforms in shallow waters can use supply boats and helidecks or walk-to-work motion compensated gangways, pictured in Figure 3, with in-situ or mobile cranes to place rigless wireline (Figures 21, 23, 28-29 and 42) or capillary coiled tubing equipment (Wilde, 2013)[92] that can perform rigless P&A.

As shown in Figure 4, small platforms in shallow water can also be accessed riglessly using a bridge link to windfarm jack-up barges with cranes for placing wireline units on the platform and/or deck space for coiled tubing units (Figures 22, 23, and 30-32) spooled to platform wells with cranes or jacking and pulling units used for removal of above seabed production equipment (Figures 10, 24-25 and 33-35).

The cranes on jack-up barges can also be used for deploying subsea lubricator systems, remote operated vehicles and divers for shallow water subsea wells to perform riserless wireline or coiled tubing P&A as well as above seabed equipment removal.

Combining rigless P&A with other decommissioning activities is not new in the North Sea, as seen on Horne Wren[48] decommissioning shown in Figures 3, 4 and 33, but it depends upon a company's view of P&A legal liabilities.

Depending upon the size of the platform, various platform decommissioning activities may be carried out concurrently. For example, some platform equipment may be removed, changed or added to better facilitate P&A and various facilities decommissioning activities can be performed at the same time as well P&A (Siems, 2016)[21].

Within deeper water, light well intervention vessels (LWIV), see Figure 23, can use subsea lubricators to riglessly P&A subsea wells (Varne, 2017)[85].

Finally, larger platforms in deeper water can use their cranes and helidecks to mobilise people and rigless equipment onto the platform's decks to avoid reactivating a decrepit drilling rig or to avoid mobilising a workover rig onto the platform.

Even when a fully functional drilling rig is available on a large platform, lower costs with less people and safer operations are achievable with rigless methods of through production equipment P&A involving fewer lifting operations that leave radioactive contaminated LSA / NORM (Woods[99],1994; Sharkey[100],2008; Mously[101], 2009; Smith[102], 2010, Barclay[103], 2010; Crouch[104], 2012) equipment within the well.

For example, Shell estimates that 10,900 tonnes of LSA/ NORM contaminated tubing and 18,980 tonnes of casing, or a total of 29,880 tonnes of steel from well P&A, are being sent to shore (Consultation Draft, 2017)[28], whereas such steel and radioactive material could have been left in-situ during decommissioning of the Alpha, Bravo, Charlie and Delta Brent platforms if rigless methods had been used.

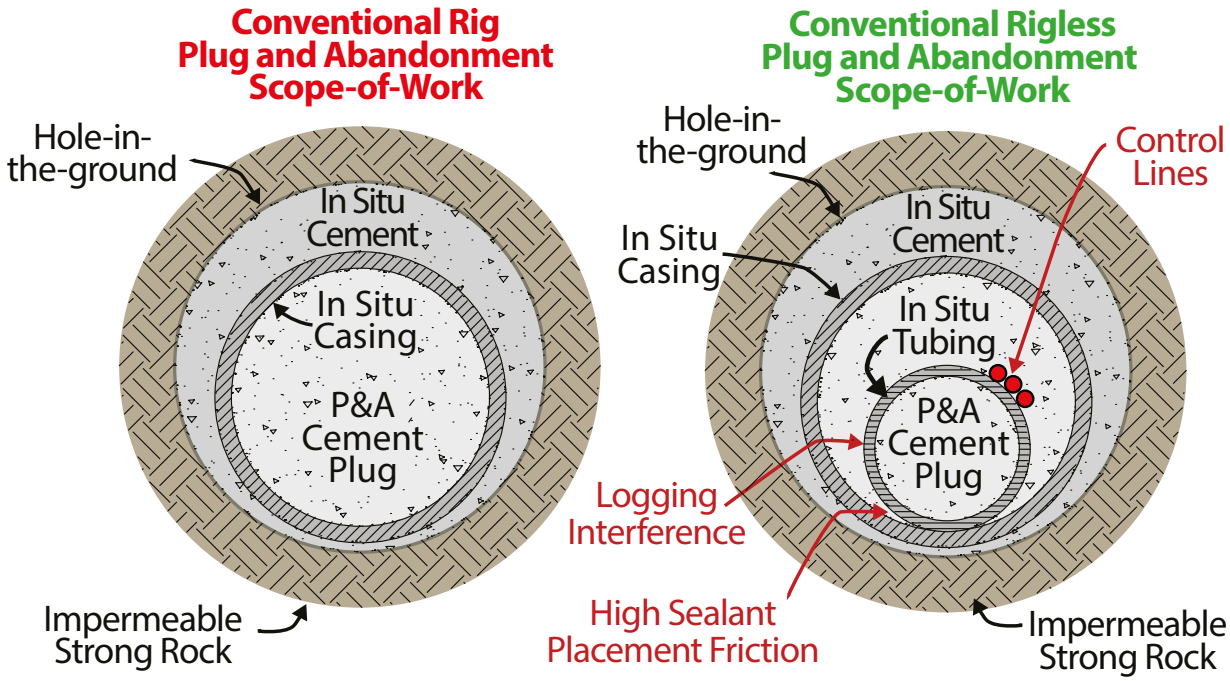

Figure 5 - Conventional Rig-based versus Conventional Rigless Scope-of-Work Differences for P&A

Work Scope Differences

As depicted in the Figure 5 plan view, a well is a hole-in-the-ground through which jointed steel casing is cemented and production equipment (tubing, valves, control lines, etc.) are inserted to control hydrocarbon flow and provide environmental barriers.

P&A plugs act like a "bath tub" plug keeping higher pressure fluids within the earth from draining into lower pressure atmospheric and water environments.

The work scope for rig-based well plugging is shown in the left frame of Figure 5 and the work scope for conventional rigless well plugging is shown on the right side of Figure 5.

Work scopes for drilling and workover rigs comprise removing the production equipment and casing to place a sealant (cement) across a single properly cemented steel tubular string (casing).

A rig-based P&A work scope is expensive not only because of the scale of logistics and rental equipment shown in Figure 2, but also because additional disposal costs are generated by rig-based cleaning, removal and disposal of radioactive scale contaminated production equipment.

Because the cost of generating and disposing of large volumes of waste onshore is less than the time cost of an offshore drilling rig, using rig time to minimise waste is uneconomic and reducing the amount of waste generated by P&A is rarely considered.

Conversely, a conventional rigless P&A scope-of-work comprises placing a sealant (cement) through and around in-situ downhole production equipment within casing before removing above seabed equipment.

Rigless P&A is substantially less expensive because the logistical and rental costs of the smaller and less complex equipment use minimal resources.

Generating waste within rigless P&A can be problematic due to a lack of space and resources and, therefore, waste minimisation is the rule rather than the exception and radioactive scale contaminated production equipment is left in-situ wherever possible.

Rigless P&A is by far the lowest present cost option but, unfortunately, current logging technology is not able to measure the quality of in-situ cement through multiple casings (Moeinikia, 2014)[63] left within a rigless P&A work scope and the legal liabilities of P&A must be considered.

P&A Legal Liabilities

Unfortunately, P&A "experts" do not agree upon which of the two Figure 5 P&A work scopes are acceptable and, ultimately, it is legal liabilities associated with a P&A work scope that drive systematic selection of drilling rigs.

Proponents of a rig-based P&A work scope recite possible hydrocarbon leakages (legal liabilities) associated with a conventional rigless P&A work scope, wherein:

- Leakages (legal liabilities) associated with potentially degraded in situ cementation cannot be measured (logged) within a rigless work scope, and
- Leakage risks associated with embedding control lines and tubulars within a P&A plug can cause high fluid frictional areas that can inhibit sealant placement and, thus, result in leakages (legal liabilities).

Conversely, proponents of a rigless P&A scope-of-work claim that the probability of leakages (legal liabilities) are sufficiently low to be acceptable and the high cost of rig-based methods are unacceptable. Such proponents advocate probabilistic justifications, i.e. quantifying the risk of leakages and deciding acceptable risk levels (legal liabilities) based upon the calculated probability of leakage (Ford, 2017)[44].

Ironically, some drilling rig P&A proponents propose marginally reducing high cost drilling rig P&A using a rigless work scope that leaves tubing in place (Aas, 2016)[25] to, in effect, accept both the cost of a drilling rig and the legal liabilities associated with potential P&A leakages.

Systematically selecting drilling rigs to perform a rigless work scope and expecting significant cost reductions is unrealistic, because drilling rigs account for 40% to 70% of well costs (Canny, 2017)[17].

In the words of Einstein, "insanity is doing the same thing over and over again and expecting different results."

Systematic use of drilling rigs for P&A is being driven by the underlying legal liabilities of future hydrocarbon leakages from abandoned wells.

Physically verifying in situ cementation, and repairing poor or lacking in situ cementation is the single most critical aspect of reducing P&A legal liabilities associated with future leakages.

The ocean provides a near perfect compliance monitoring environment, whereby gathering and analysing the composition of slicks on the ocean's surface or bubbles coming from the seabed above previously abandoned well(s) could cause serious legal and reputational issues if the analysis showed that a plugged and abandoned well is leaking.

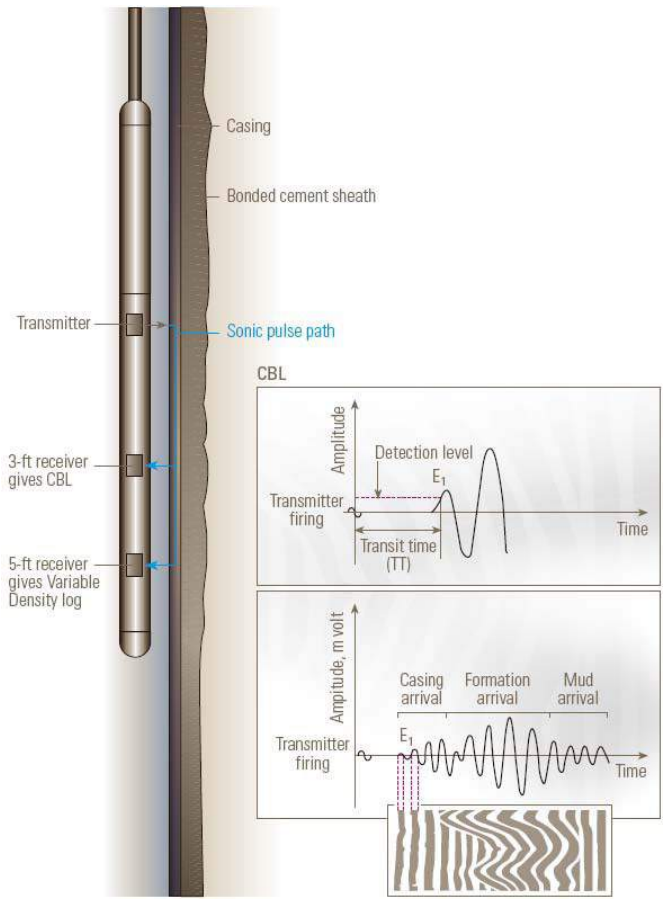

Figure 6- Cement Bond Logging (Williams, 2009)[19]

If the Operator cannot demonstrate that in situ cement was good at the time the adjacent P&A plug was placed, the Operator may be liable for leakages from natural causes beyond its control.

The Elgin G4 well intervention incident, which occurred during P&A, clearly documents the potential value of logging in situ equipment and cementation that can fail when the overburden above a reservoir moves or fractures due pressure depletion and compaction (Henderson[26], 2014).

Operators could be liable in perpetuity for well leakages unless they can prove P&A was performed properly to, thus, demonstrate that any future leakages resulted from natural forces beyond their control.

Accordingly, given that a conventional rig-based work scope can measure (log) in-situ cementation and casing, whereas the work scope of a conventional rigless P&A cannot, presently, the legal liabilities for a rig-based P&A scope-of-work are obviously lower.

Cement Bond Logging Measurements

NORSOK requires a minimum length of 30 metres measured depth for annular cement verification by cement bonding logs (Delabroy, 2017)[27] and Oil and Gas UK guidelines[2,30] specify a minimum of 100 foot (30m), if previously logged cement, or 1,000 feet (300m) of cement above the base of the intended barrier if estimated from original differential pump pressures.

Also, numerous Shell presentations publicly advocate the requirements of cement bond logging and, during the Aberdeen OGA Hackathon in June 2016, ConocoPhillips stated within its end-of-the-day summary that through-tubing-logging was the "holy grail" needed for compliant rigless P&A.

Unfortunately, current logging technology is not able to log through multiple casings (Moeinikia, 2014)[63]. Also, there are no accurate methods of determining cement levels in a rigless work scope for both tubing and annulus (Oil & Gas UK, 2015)[2].

Williams[19], et al., teach in Figures 6 and 7 that modern cement bond and variable density log measurement tools send low frequency omni-directional pulses that induce longitudinal vibrations in the casing. Receivers within the logging tools then record the reflected vibrations and when casing is bonded to hardened cement and rock, the vibration of the casing is attenuated and the reflected signal amplitude is relatively small.

Echoes and vibrations caused by unsecured and potentially eccentric and/or helically buckled production tubing are unpredictable and cannot be accurately separated from casing vibrations and, unfortunately, render bond and variable density logging tools unusable when the unsecured tubing is left in-situ.

Experiments show that it is possible to have sealant (cement) well placed in the annulus when tubing is left in the hole. Also, microannuli are relatively small and probably non-uniform. Furthermore, the presence of control lines may not represent additional leakage paths (Aas, 2016)[25].

Unfortunately, while recent research shows that rigless P&A plug cementing through and around the tubing may be acceptable, it is a moot point because it is impossible to measure the integrity and quality of in-situ cement behind the casing without first moving the tubing.

Various authors (Woolsey[53], 1988; Morlta[54], 1992; Settari[55], 2002; Williams[19], 2009; Marbun[56], 2011; King[57], 2013; Feng[52], 2016) have reported on the effects of well construction failures, reservoir compaction and changes in overlaying geology that can affect in-situ cementation and invalidate historical records of well construction.

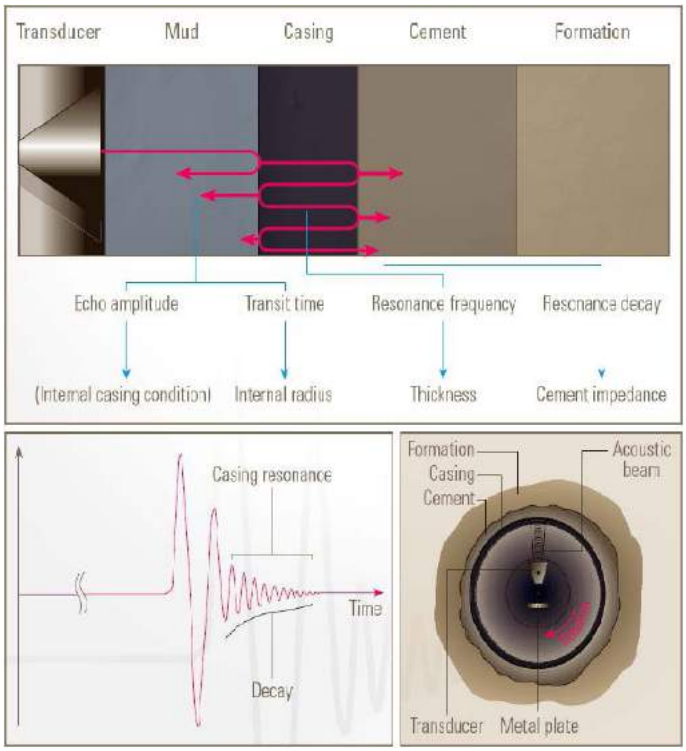

Figure 7 - Pulse Reflection (Williams, 2009)[19]

Placing a useless P&A plug within casing with annuli leakages may exemplify gross negligence as, without log evaluations, there is little evidence otherwise. Evaluating cement in older wells can be particularly challenging (Smolen[132], 1996; Benge[65], 2014), but it legally documents P&A competency.

Accordingly, physically measuring in-situ conditions and cement bonding can comprise legal evidence usable to avoid claims of gross negligence should P&A wells ever leak, wherein defendants can blame natural causes for the leakages.

When production tubing is moved away from the casing, using a rig-based approach or, alternatively, using Oilfield Innovations' patented rigless method, cement bond and variable density logging measurements are possible, whereas conventional rigless methods cannot assess the quality of in-situ cementation and, thus, may reduce present costs but not future legal liabilities associated with well leakages.

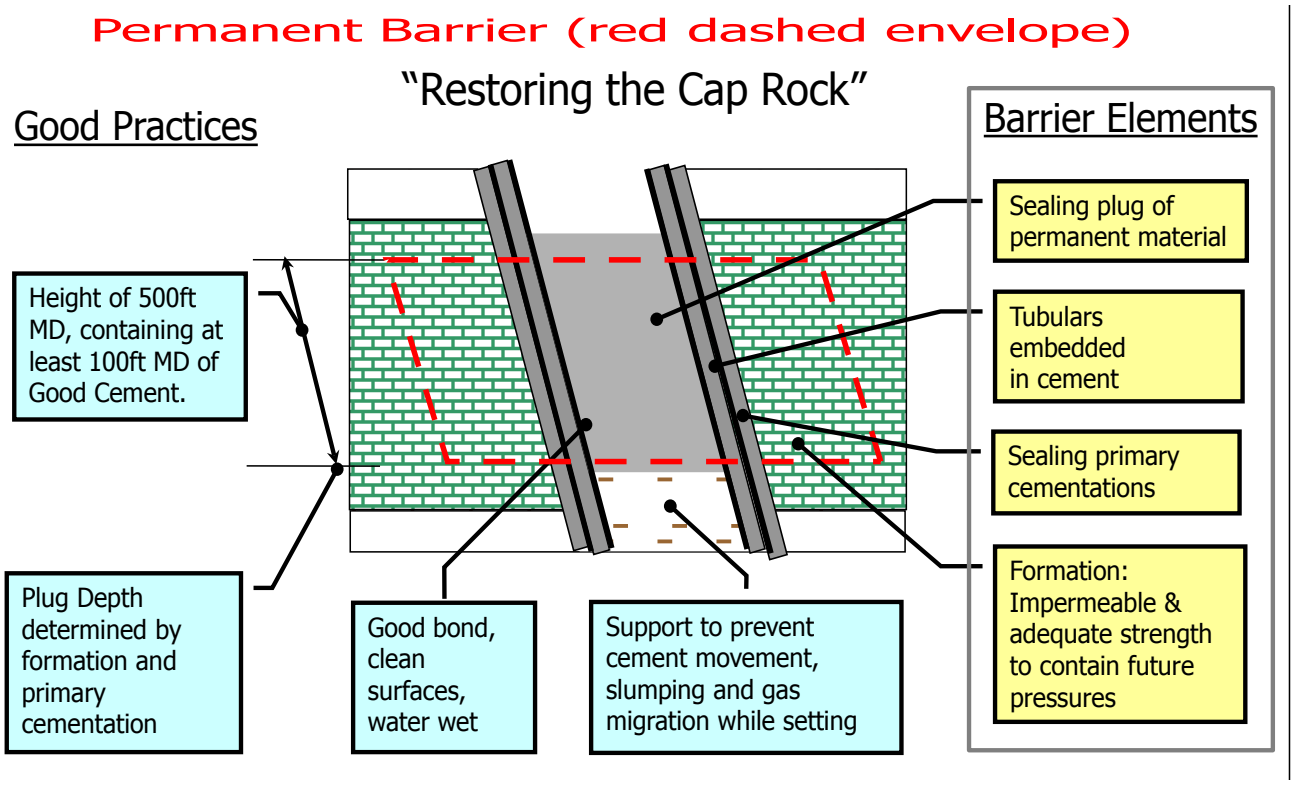

Figure 8 -Good P&A Plug Practices (Oil & Gas UK, 2015)[2]

As-Low-As-Reasonably-Practicable (ALARP)

Oil and Gas producers may, in perpetuity, be legally liable for environmental pollution caused by well P&A when it is relatively easy to, in perpetuity, capture, analyse and confirm the source of a slick upon the ocean's surface or hydrocarbons bubbling from the seabed.

Companies perceive legal liabilities differently and, therefore, a single industry-wide P&A standard does not exist and local requirements vary widely between prescriptive and goal setting regimes.

Generally, two (2) permanent P&A plug barriers to fluid flow are accepted when the zone requiring isolation is hydrocarbon-bearing or over-pressured and water-bearing.

Such primary and secondary (backup) barriers should be set above zone(s) with flow potential across a suitable caprock that is impermeable, laterally continuous and has adequate strength and thickness to contain the maximum anticipated pressures from the zone(s) being isolated.

Figure 8 shows that an Oil and Gas UK[2] permanent barrier constitutes a good cement column of at least 100 feet (30 m) measured depth (MD). Where possible 500 feet MD barriers are set, presumably due to drilling rig P&A cement contamination when using a small diameter stinger (Rove, 2014)[29].

Oil and Gas UK recites[2] that at least 100 feet (30m) of good annular cement should be verified by logging, but the industry trade group recognises the risk tolerance of their members varies and further recites that historic data can be used in a probabilistic manner to estimate whether good in-situ cement exists.

King[57] and Ford[44], et al., advocate "fit for purpose" risk-based approaches over prescriptive standards like NORSOK D-010. A risk-based approach means that any P&A solution is expressed in terms of the leakage risks shown in Figure 9, which can be formulated in terms of whether the (permanent) barrier system will fail in a given time period measured against the corresponding consequence in terms of leakage to the environment.

Unfortunately, risk-based P&A leak calculations may, or may not, comply with the UK legal precedents of keeping risks as-low-as-reasonably-practicable (Aguilar, 2016; Taylor, 2014)[46,47].

Landmark UK legal cases in 1947 and 1954 established that "The test of what is (reasonably practicable) is not simply what is practicable as a matter of engineering, but depends on the consideration, in the light of the whole circumstances at the time of the incident, whether the time, trouble and expense of the precautions suggested are or are not disproportionate to the risk involved, and also an assessment of the degree of security which the measures may be expected to afford (Marshall v Gotham Co Ltd, 1 All ER 937 (HC) 1954)."

Elgin G4 well abandonment incident (Henderson, 2014)[26] is evidential of how geological changes resulting from production depletion can cause hydrocarbon leakages from previously unproducible zones, wherein construing rig-based P&A to measure in-situ cement quality as a disproportionate sacrifice is ludicrous when other Operators typically use rigs for P&A cement quality measurements.

An annulus barrier is necessary for P&A and it does not matter whether the annular barrier is cement, shale (Willams[29], 2009 Fjær[111],2016) or salt (Lavery 2017)[49]. Provided logging measurements at the time of P&A can confirm an annular barrier, companies can prove that P&A was properly performed and the laws associated with disproportionality can be applied to the benefit of the Operator.

Hydrocarbon vs. Water Risk-Based Approach

Many authors (Lonnes[66], 2009; King[57], 2013; Taylor[47], 2014; Guo[64], 2014; Benge[65], 2014; DNVGL-RP-E103[14], 2016; Aguilar[46], 2016; Ford[44], 2017) discuss the merits and drawbacks of risk-based approaches to P&A.

Without delving into pedantic arguments, water and hydrocarbons are two different types of fluids with very different legal liabilities.

Adopting a risked based P&A approach for water bearing subterranean zones, located below the ocean far from any drinking water sources, can have negligible consequences given the impossibility of finding a water leak into an ocean, whereas catching, analysing and confirming the source of hydrocarbon slicks on the ocean surface or subsea bubbles leaking from a well P&A is realistically possible and has significant legal, reputational and cost consequences.

Using the Oil and Gas UK P&A Guidelines[2] of accepting old construction records and using work by Aas[25], et al., involving a risked based approach to leaving tubulars within the well during isolation of water bearing zones, below an ocean, has minimal legal liability; whereas the same cannot be said about P&A of hydrocarbon fluids which are lighter than water, naturally float to surface through any available leak paths and are easily identified at seabed and on the ocean's surface.

Accordingly, a risk based approach to water bearing zones has few or no consequences, whereas the same cannot+ be said about hydrocarbon zones when accurately estimating any future event is impossible and the consequences of hydrocarbon leakages are substantial.

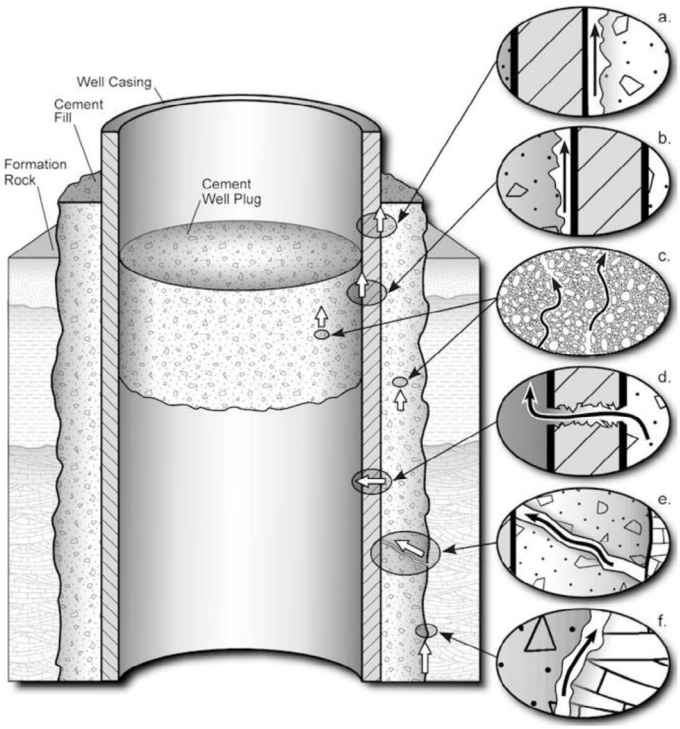

Figure 9 - Potential Leak Paths in P&A Plug (Gasda, 2004;Ford, 2017)[43,44]

Regardless of risk-based versus traditional P&A approaches, or whether you believe isolating water bearing zones has a lower risk than isolating hydrocarbons, drilling rigs are not a P&A requirement. Rigless equipment is available for all P&A tasks, albeit there is no one-size-fits-all solution. For example, where Oilfield Innovations method cannot pull casing and conductors, rigless Pulling and Jacking Units (PJU) can, as pictured in the Figure 10 P&A being performed on a damaged wellhead platform (Canny, 2017)[17].

Figure 10 - Rigless Pulling & Jacking Unit (PJU) on damaged platform well (Canny, 2017)[17]

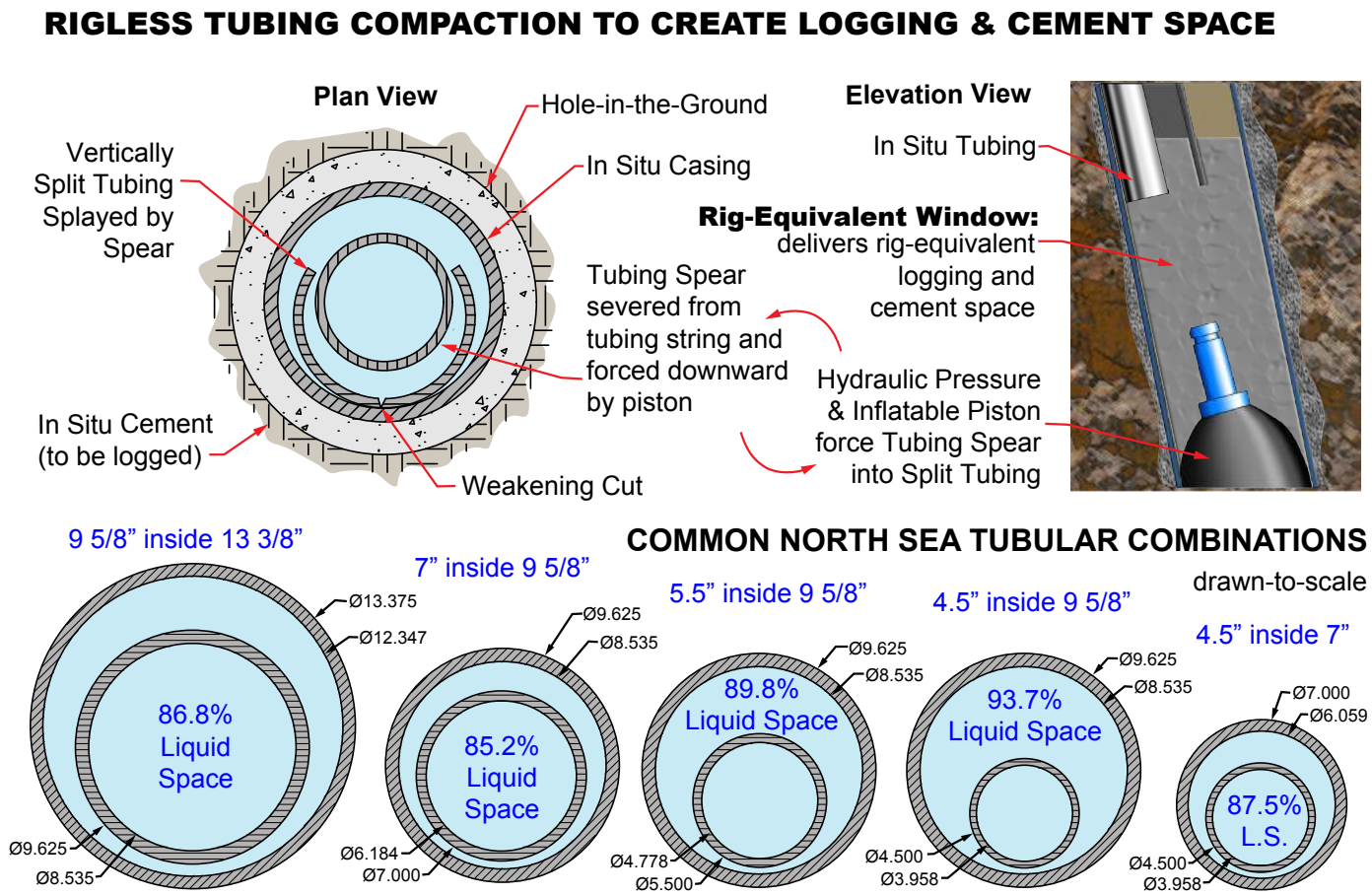

Figure 11 - Plan View: Universal Method of Rig-Equivalent Rigless Abandonment

Universal Rigless P&A Method

Step changes in P&A cost require stopping the systematic selection of drilling rigs for P&A through Operator Corporate Management and Governmental influence away from the status quo.

Oilfield Innovations have patented a rigless P&A method, shown in the Figures 11 & 12, that compacts portions of downhole production tubulars into the 80% to 90% liquid spaces of a well to form a "Rig-Equivalent-Window" free of tubular interference for compliance logging and cementing, whereby the logistics of rigless P&A can keep legal liabilities and risks as-low-as-reasonably-practicable and remove arguments for using drilling rigs to, thus, allow Oil and Gas Operator Corporate Management and Government guidance for combining rigless P&A with other decommissioning activities and logistics to reduce the total offshore UK P&A cost by 30% to 60% (£3.3 to £6.6 billion).

The lower half of Figure 11 illustrates various common North Sea tubular combinations, which have 85% to 93% liquid space within the inner circumference of an outermost casing. Oil Country Tubular Goods (OCTG) are used worldwide and have standardized proportions and combinations that are typically between 80% and 90% liquid space, which makes our P&A method universally applicable.

Creating the Figure 11 "Rig-Equivalent Window" provides a rig-based P&A work scope, shown in Figure 5, where unobstructed logging measurements of in-situ cement, shale (Willams[29], 2009; Fjær[111],2016) or salt (Lavery 2017)[49] annulus barriers can riglessly occur to provide legal evidence that, so-far-as-reasonably-practicable, safe and environmentally responsible P&A occurred.

Split, weakened and severed tubing can easily be compacted into the 80% to 90% liquid spaces of a well to form a Rig-Equivalent-Window for proven conventional logging measurements confirming placement of a compliant P&A plug, as further illustrated in Figure 12 elevation view.

Explanatory Method Steps

The various steps of Oilfield Innovations' universal rigless P&A method of in-situ cement verification and plugging illustrated in Figure 12 elevation view are similar or equivalent to other common downhole operations.

Step #1 of Figure 12 depicts vertically splitting in-situ production tubing to remove the strength of its circular shape, wherein the step requires qualification.

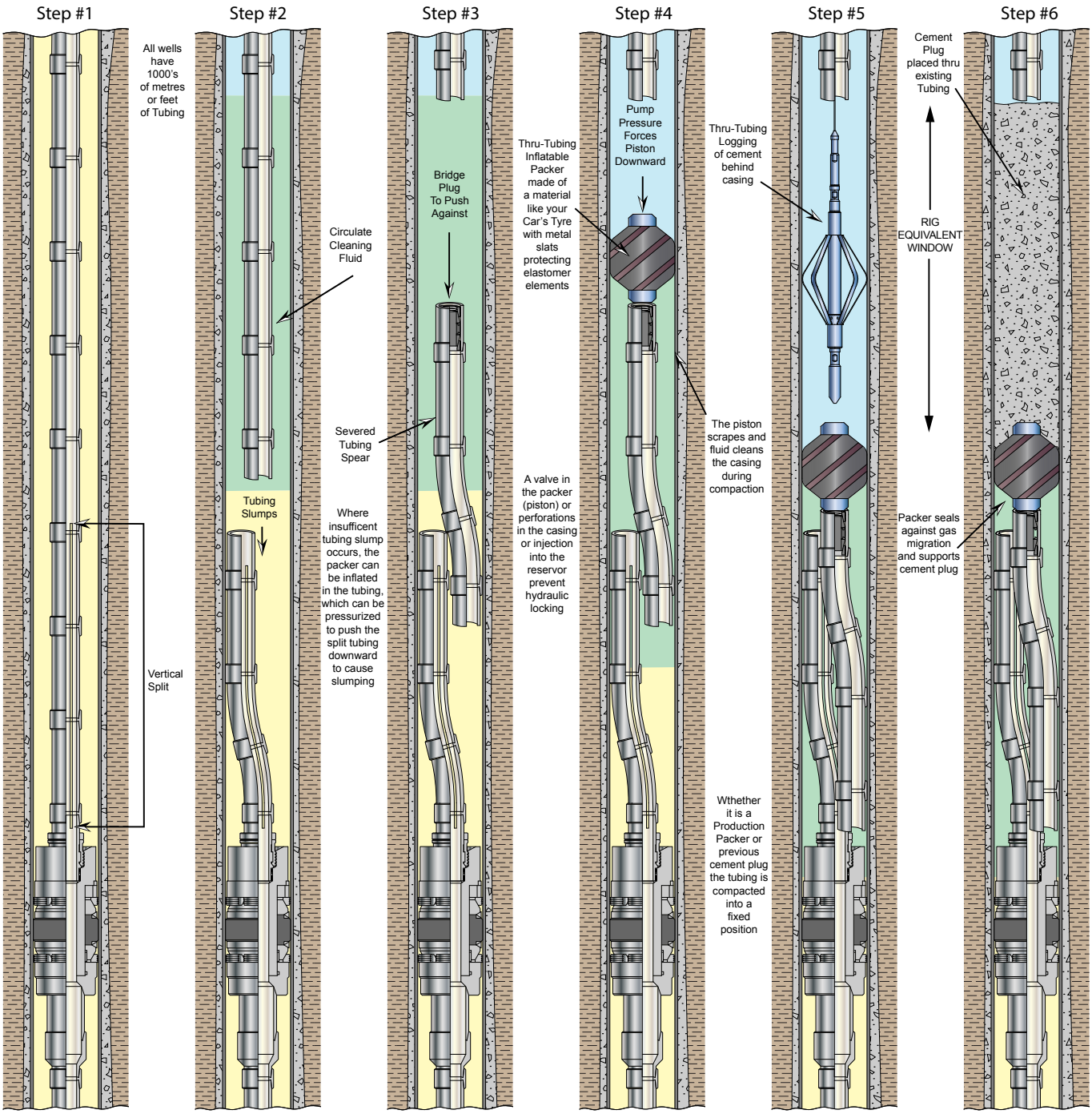

Figure 12 - Elevation View: Universal Method of Rig-Equivalent Rigless Abandonment

Step #2 of Figure 12 illustrates the "common task" of severing the tubing above the split and circulating a cleaning fluid into the annulus space between the tubing and casing.

Step #3 of Figure 12 shows the "common task" of placing a mechanical plug for the subsequent packer (piston) to push against and then severing above the mechanical plug to create a tubing spear that can be pushed alongside the split tubing. Oilfield Innovations have proved the concept a tubing spear.

Step #4 of Figure 12 depicts the "common task" of inflating a packer in the casing and hydraulically pumping fluid into the well to push the packer (piston) downward to force the tubing spear alongside the split tubing, wherein the step of using proven inflatables packers requires qualification.

Step #5 of Figure 12 illustrates "common" through tubing logging measurements of the in-situ cement within the Rig-Equivalent-Window space created to measure cement bonding. Alternatively, research shows that shale (Willams, 2009)[29] or salt (Lavery 2017)[49] can also comprise an annulus barrier that can be confirmed by logging measurements.

Step #6 of Figure 12 shows "common" placement of a P&A sealant (cement) plug that is supported by the compacted tubing, whereby the packer element's casing seal prevents gas migration during sealant curing (hardening) to provide a universally compliant P&A plug.

Proof of Concept

There is nothing magical about the precisely defined properties of oilfield steel tubulars.

Oilfield Innovations method is not rocket science, it uses a piston to bend cut metal. Finding anything more simplistic may be impossible.

Oilfield Innovations have performed initial proof of concept experiments[20], shown in Figure 13, and found that shredding tubulars decreased compaction resistance and resulted in tubular buckling and compaction ratios of around 46% within a "worst case" frictional and casing diameter scenario of 2 $^{3}/_{8}$ inch (60.3mm) tubing inside of 5 ½ inch (139.7mm) casing.

The predominate North Sea production casing size for P&A plugs is 9 $^{5}/_{8}$ inch (244.5mm) casing, which has a piston area of 57 in^2 (368 cm^2) and can provide a piston force 319% larger than 5 ½ inch (139.7mm) casing with a 17.9 in^2 (115.5 cm^2) piston area.

API Specification 5CT defines the properties of oilfield steel tubulars. The crushed J55 tubing in Figure 13 had a minimum yield strength of 55,000-psi (379.2 N/mm^2) and a maximum yield strength of 80,000-psi (551.6 N/mm^2). Yielding 1in^2 (6.5 cm^2) of J55 steel requires forces between 55,000-lbf (24.9-t) and 80,000-lbf (36.3 -t), which can be divided by the piston's cross-sectional area of 17.9 in^2 (115.5 cm^2) to determine compaction pressures of 3,057-psi (210.7 bar) and 4,462-psi (307.6 bar).

During the Figure 13 tubing compaction simulation, bending started at 3,000-psi (206.8 bar) and stopped at 4,200-psi (289.6 bar), which matches the defined properties of the steel.

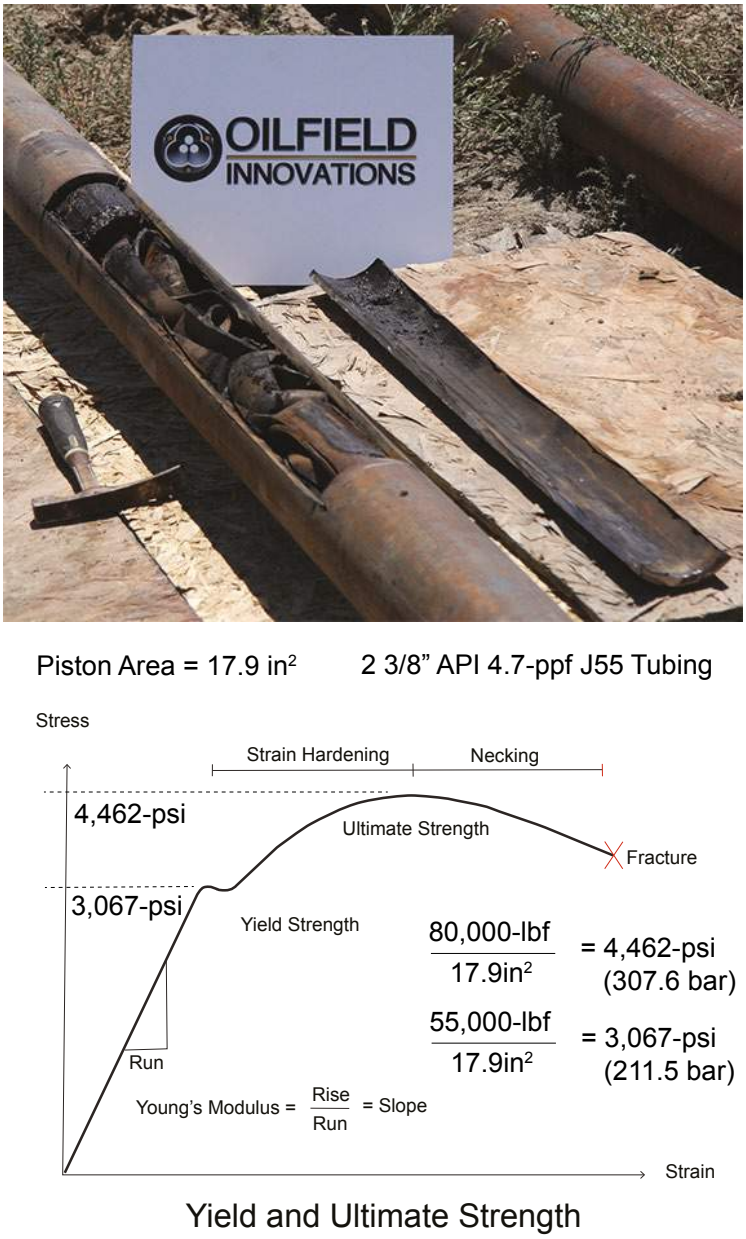

Figure 13 - Proof of Concept

The North Sea predominantly uses tubing sizes of 4 ½ inch (114.3mm) and 5 ½ inch (139.7mm) outside diameter with steel grades of L80 or P110. API grade L80 steel has a minimum yield of 80,000-psi (551 N/mm^2) and maximum yield of 95,000-psi (655 N/mm^2). API grade P110 steel has a minimum yield of 110,000-psi (758.4 N/mm^2) and maximum yield of 140,000-psi (965.3 N/mm^2).

Yielding 1in^2 (6.5 cm^2) of L80 within 9 $^{5}/_{8}$ inch (244.5mm) casing using a piston area of 57 in^2 (368 cm^2) requires a minimum pressure of 1,400-psi (95.5 bar) and maximum pressure of 1,600-psi (110.3 bar).

Yielding 1in^2 (6.6 cm^2) of P110 within 9 $^{5}/_{8}$ inch (244.5 mm) casing using a piston area of 57 in^2 (368 cm^2) requires a minimum pressure of 1,920-psi (132.4 bar) and maximum pressure of 2,447-psi (168.7 bar).

North Sea wells are typically designed for pressures of 5,000-psi (344.7 bar) or 10,000-psi (689.5 bar) and can easily accommodate pressures between 1,400-psi (95.5 bar) and 2,447-psi (168.5 bar).

These calculations use undisputed new pipe manufacturing specifications. Old tubulars within a well may yield at lower values. There is absolutely no doubt that tubulars can be compacted into the 80% to 90% liquid space of a well. As shown in Figure 14, it is only a matter of cutting tubulars to reduce the bending areas of steel with known properties.

Oilfield Innovations is working with Oil and Gas Innovation Centre (OGIC), the University of Glasgow and the Oil and Gas Technology Centre (OGTC) to perform further mathematical simulations as discussed in Appendix A.

Further technical justification with answers to frequently asked questions can be found in Appendix B.

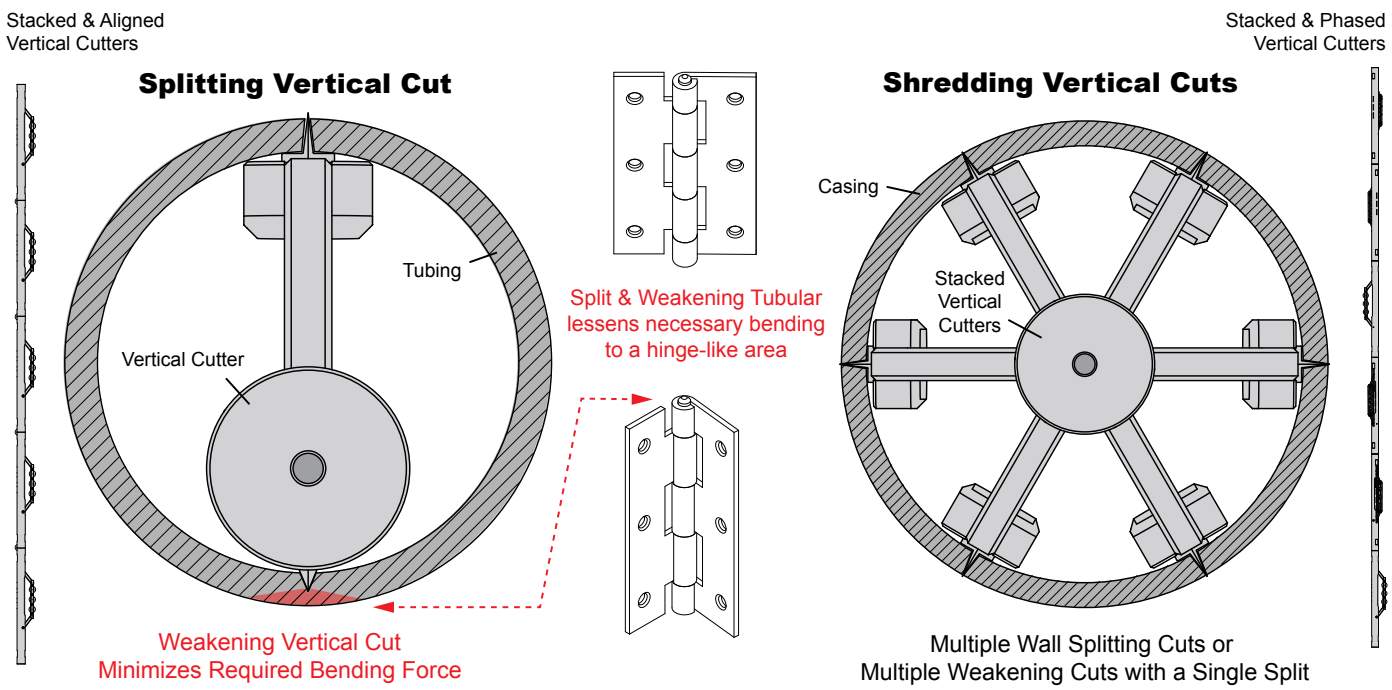

Figure 14 - Splitting and Weakening of Tubulars to Reduce Compaction Forces or Facilitate Repair

What we have and what we need

Drilling rigs account for 40% to 70% of construction and P&A cost (Canning, 2017)[17] and removing the reasons for selecting drilling rigs could save Operators and Governments billions.

Only logging measurements of in-situ cement can remove legal liabilities of P&A and, because our rigless method can provide the legal security of a rig-based P&A, our patents have a significant "enabling" value to Operators and the United Kingdom that could be as much as £3.3 to £6.6 billion.

Development costs for our method are infinitesimal compared to the savings, which could be recovered within the first two wells abandonments.

Rigless P&A methods have been available for many years, yet large Operators will not use them to reduce P&A cost.

Operators select drilling rigs to avoid the legal liabilities of not measuring in-situ cement during P&A.

That paradigm needs to change.

Oilfield Innovations have a method enabling in-situ cement verification but need funding to qualify a simplistic method of cutting and bending tubulars walls into a relatively large space to provide a rig-equivalent work scope using rigless P&A equipment that can be combined with other decommissioning activities and logistics.

Our method allows Operators to divert P&A funds to exploration and production drilling, Scotland could establish itself as the worldwide centre of excellence for P&A and the toxic labels placed upon UK North Sea assets burdened by decommissioning liabilities could be removed so that smaller companies could assume ownership and continue production.

Cutting and weakening tubulars creates a simple hinge as shown in Figure 14. Bending a split piece of tubing is not difficult and spearing a whole piece of tubing into the 80% to 90% liquid space is equally simple (see Figures 11 and 12). The properties of steel are known and we have proven the concept using the worst-case friction and piston size (see Figure 13), but we understand that people want to see it for themselves.

Oilfield Innovations can contribute patents ownership for development funding beyond the University of Glasgow & OGIC project (see Appendix A).

Oilfield Innovations comprises two (2) engineers who own patented legal protection for cutting and using a piston to bend steel within a hole-in-the-ground to provide a space for regulatory compliant logging and cement. Unfortunately, we have gone as far as our limited resources allow.

Oilfield Innovations can apply for OGTC development support, but we will need matching development funding and support from Operators, Service Providers and/or Venture Capitalists.

Whether you consider cutting and bending steel with a piston to be new technology, or not, developing new technology just doesn't get any simpler or have any higher rates of return.

We would need to understand the objectives and financial requirements of funding, but we are flexible and willing to explore various arrangements between New Technology

Figure 15 - Reinventing the Wheel

Organisations, Operators, Service Companies and/or Venture Capitalists.

We are marketing our patents to cover tool development, test well and field trial qualification costs.

Oilfield Innovations contribution can comprise: selling patents to pay for development, using the patents as collateral for financing development, or transferring the patents to qualified company(s) who can match governmental development funding requirements.

Oilfield Innovations can offer a low-cost simple universal solution to verifiable P&A, but we can't change the system. The systematic selection of drilling rigs for P&A needs to change and only the Operator Corporate Management and Government can influence that change.

Conclusion

Reinventing P&A is like reinventing the wheel. Now is the time for change in the North Sea and combining universally compliant rigless P&A with other decommissioning activities is the change that is needed. The most challenging aspect is the industry's natural resistance to change.

It is no coincidence that experts systematically recommend drilling rig P&A and ignore published lessons in rigless P&A (Coronado[78], 1991; Edmondson[96], 1996; Olsen[79], 2001; Foster[86], 2001; Khurana[5], 2003; Håheim[9], 2003; Munkerud[71], 2007; Lonnes[66], 2009; Jøssang[72], 2010; Fjærtoft[80], 2011; Flett[87], 2011; Zwanenburg[94], 2012; Zijderveld[73], 2012; Morrison[74], 2013; Willis[75], 2013; Osorio[81], 2013; Wilde[92], 2013; Birk[95], 2013; Krüger[76], 2014; Karlsen[22], 2014; Webb[93], 2014; Løver[77], 2015; Loov[82], 2015; Webb[83],2015; McLeod[88], 2015; Stein[70], 2016; Numbere[84], 2016; Rivas[89], 2016; Mackie[91], 2016; Varne[85], 2017; Tanoto[109], 2017).

Experts are comfortable using drilling rigs for P&A and letting Corporations and Governments pick up the P&A bill.

Drilling rig cost accounts for 40% to 70% of well and P&A costs (Canny, 2017)[17] and, therefore, all rig-based operations are justified based upon the rig time needed to complete a task.

When asked to reduce time and cost, drilling rig P&A proponents recommend Perf & Wash (Ferg[32], 2011; Abshire[69], 2012; Khalifeh68, 2013; Moeinikia[63], 2014; Aas[25], 2016; Delabroy[27], 2017) to avoid long and costly cutting, milling and pulling operations.

What the experts don't tell you is that Perf & Wash provides a rigless work scope that could have been accomplished without using a drilling rig costing 40% to 70% of the total P&A expense.

People naturally fear change and will use technical jargon that sounds like rocket science to maintain the status quo; however, when questions are answered simply, it is easy to see that it is not rocket science.

The distinguishing difference between rig and rigless work scopes comprises measuring the quality of in-situ cementation

to reduce or avoid P&A leakage liability.

Oilfield Innovations' method of riglessly enables logging the quality of in-situ cementation and provides a rig-based P&A work scope using rigless P&A equipment that can be combined with the logistics of other decommissioning activities to provide cost savings of 32% (Siems, 2016)[21] to 60% (Varne, 2017)[85].

The United Kingdom's Horne Wren decommissioning (Martin[48], 2015), pictured in Figures 3, 4 and 33, demonstrates that such techniques are not confined to the Gulf of Mexico.

Experts cloak P&A within technical jargon that makes it sound like rocket science but, in fact, universally acceptable P&A is simply putting cement into a hole-in-the-ground where in-situ cementation has been confirmed.

Oilfield Innovations' patented method of in-situ cement verification is not rocket science, it is simply making room for logging tools by cutting and bending a small amount of steel with known properties using a piston and a pump.

Oilfield Innovations has and will continue overcoming the technical challenges of providing rigless logging of in-situ cement, but we cannot overcome either the financial hurdles of qualifying our method or industry's natural resistance to change.

We need to understand the objectives, requirements and limitations of any parties interested in assisting with financing in exchange for ownership of our patents. Efficient markets can provide cost reduction below the next most expensive method, wherein our method could economically compete with current rig and rigless P&A worldwide.

Our method could also enable other new methods like thermite self-sintering ceramic plugs (Lowry, 2015)[31] and those listed in Appendix B.

Operator Corporate Management and Government have oversite and can overcome the natural resistance to change by, for example, dictating that production well abandonments be included within decommissioning, wherein experts would need to justify not combining well P&A with other decommissioning logistics.

Obviously, companies who rely upon the present system of rig-based P&A will be outraged and the livelihoods of their employees will be impacted, but the alternative status quo may wipe out future revenues from the UK North Sea (Financial Times, 2017)[1] and cause government austerity measures that affect far more people's livelihoods.

North Sea oil and gas is a resource that affects countless lives. The short-term controversy of switching to rigless P&A will ultimately benefit drilling rig proponents when money is not wasted on P&A and directed toward drilling exploration and production.

Inclusion of a universally acceptable rigless P&A within the overall decommissioning logistics can provide a step change in total decommissioning costs and improve oil and gas economics by directing funds to more productive activities.

Oilfield Innovations can explain what needs to change and we have in-kind funding comprising legal patent protection that we will exchange for development funding, but we can't provide matching cash-funding nor can we overcome natural industry resistance to change without help.

Further Information

Addition detailed information on the Oilfield Innovations' rigless P&A method described above is included in Appendix B, please provide this document to your engineers and we would be happy to answer any further queries. For additional information or further queries please contact Clint Smith or Bruce Tunget at the below email addresses.

Notes and references

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APPENDIX A

North Sea Tubular Compaction Simulation Project

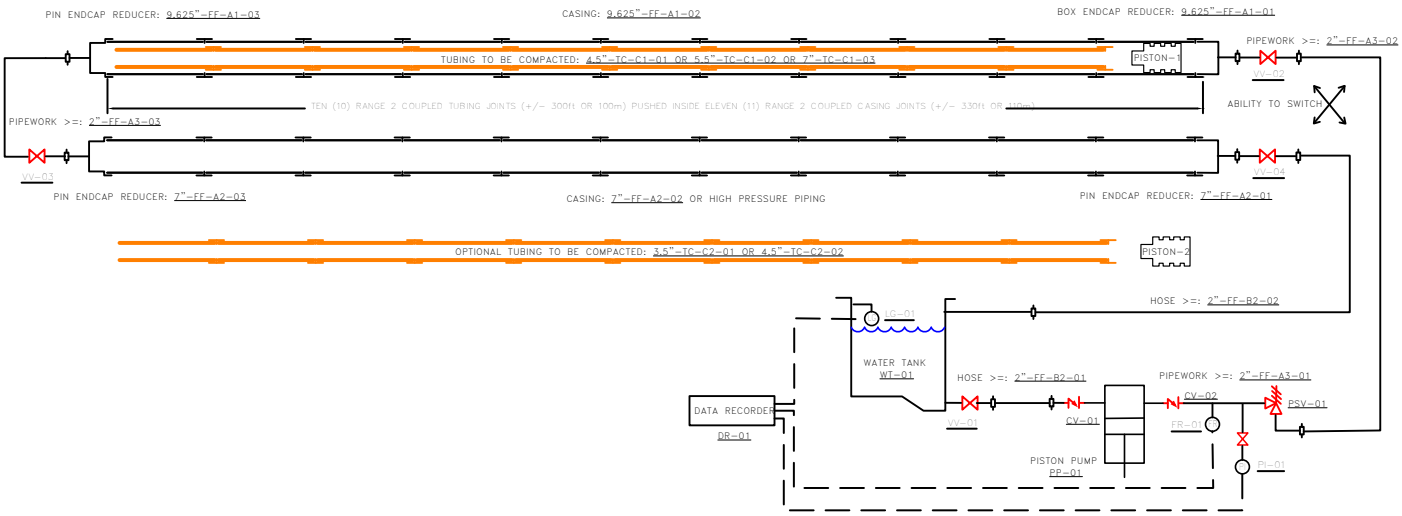

Figure 16 - Data Collection Proof of Concept Simulations with North Sea Tubular Sizes

Proof of Concept Experiments

Vertical cutting and weakening is the most important aspect of tubular compaction, wherein much of the misconception about the viability of our method results from misunderstanding the yield strength of steel and applicable bending forces.

Considerable oil and gas tubular buckling research (Wu[40], 1993; McCann[42], 1994; Hishida[41], 1996; Zdvizhkov[39], 2005, Michell[35-38], 1986-2006) has demonstrated that wall friction associated with helically buckled "whole" tubing is considerable.

The strength of a circular tubular shape is a function of its cross-sectional area, second moment of the area (bending) and polar moment of its circular section (torsion), wherein applying force to constrained "whole" tubulars helically buckles the tubular within the bore until high fictional forces prevent further buckling.

During proof of concept experiments[20], Oilfield Innovations found that applying axial force to "whole" tubing, having an unbroken circumference constrained within casing, resulted in helical buckling and friction that limited tubing failure to a short length immediately adjacent to the compaction piston.

During further proof of concept experiments[20], shredding tubulars decreased their polar and area moments by a factor of about ten and resulted in tubular buckling and compaction ratios of around 46%.

Accordingly, Oilfield Innovations' are working with the Oil and Gas Technology Centre (OGTC), Oil and Gas Innovation Centre (OGIC) and the University of Glasgow to perform mathematical modelling and experiments in the buckling of circumferentially cut tubulars constrained within a well bore to better understand and develop engineering equations.

Compaction Data Collection

The Figure 16 simulation data collection configuration will be similar to an OGTC and OGIC compaction project to collect data for University of Glasgow mathematical modelling of the compaction process shown in Figure 17.

A triplex positive displacement pump will force fluid into horizontal casing to push a piston that will drive a whole piece of tubing into a split piece of tubing.

If possible an inflatable piston will be used for the compaction simulations, otherwise a casing cementing wiper plug will be used to provide a seal with a metal piece protecting the wiper plug from the tubing being compacted.

Casing and tubing with known properties will be used while the pressures and volume pumped and returned will be digitally recorded to chart the relationship between applied force and percentage compaction.

Collected data and photographic results will then be used for bench scale modelling and computer modelling of the compaction process so that it can be predicted for any well configuration.

Compaction System Modelling

Oil and gas well compaction system will be comprised of the volume of fluid within the well bore, whereby a piston and various equipment and fluids are added to the casing volume while other fluids are injected or moved across the piston to facilitate compaction of in-situ equipment into the 80% to 90% liquid space of the well.

This process can be visualised as driving a tubing spear into spit tubing shown in Figures 11 and 12.

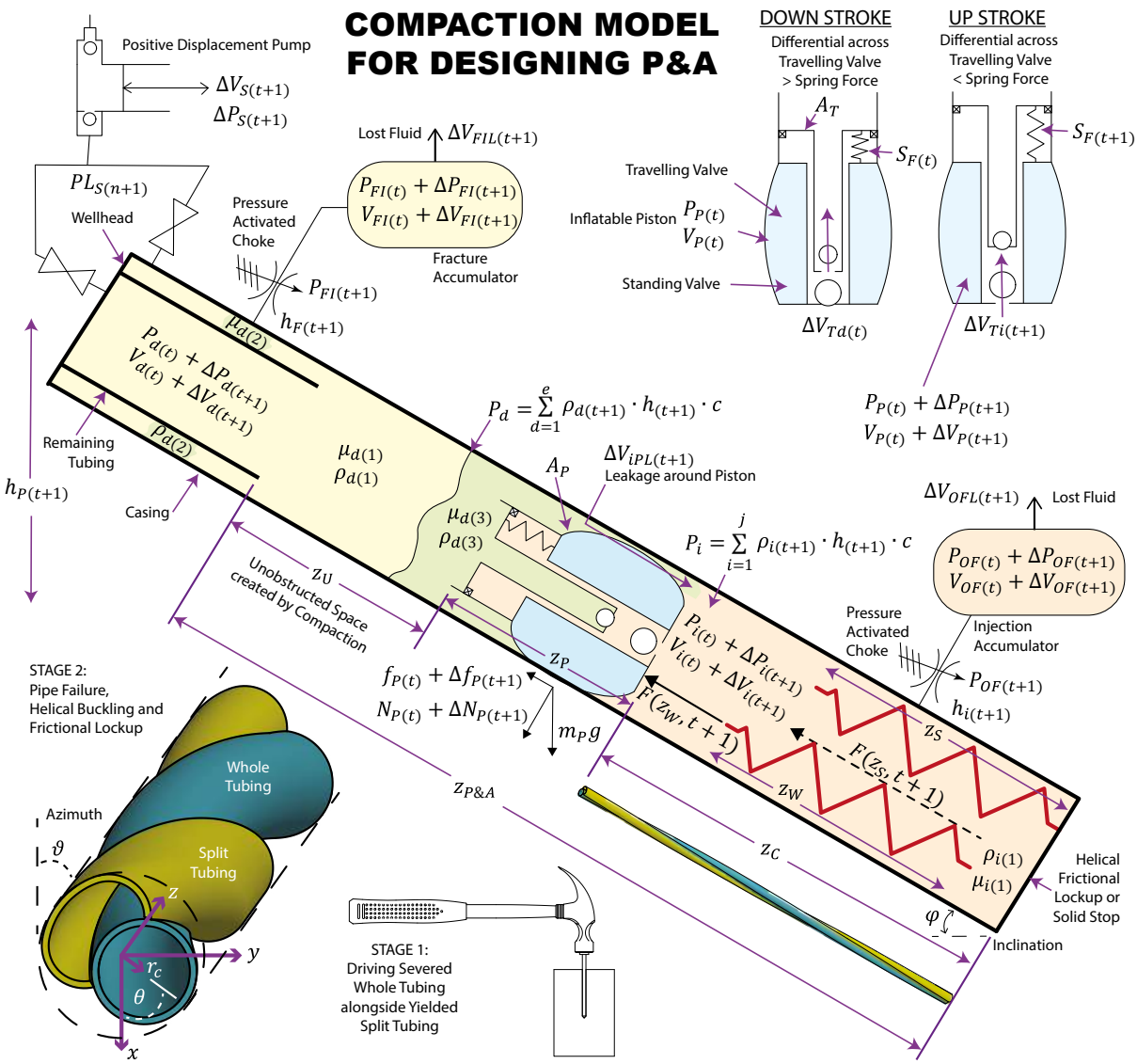

Figure 17 - OGIC & University of Glasgow Project Analytical Validation and Mathematical Modelling

Fluids will exit the system when fluids and the packer are injected into the casing volume. The volume-in and volume-out system has entries and exits comprising geologic formations, the bore of the production tree and the annulus valves.

The volumes between entry and exit points, as well as the specific gravity and viscosity of the fluids, can be estimated or will be known, wherein mathematical optimisation can be used to select the right types and weights of fluid.

Compacted tubing will act as a spring or frictional resistance while fluid friction associated with fluids entering and leaving the well will also affect compaction and pump pressures.

The specific gravity of fluids added to the top of the piston can be used to increase the force on the piston to compensate for fluid or compacted tubing friction.

Fluid above the piston can escape through leaks in the casing or leaks around the packer, while fluid below the piston can either be injected into a formation below the piston or pass through the piston via a valve arrangement.

The standing and traveling valve arrangement pictured in Figure 17 can improve hydraulic compaction performance, but other valves or orifices are also applicable.

By defining the system and mathematically modelling it, various parameters can be changed to allow downhole compaction engineering to take place.

The resulting mathematical model and available data will be used to design well P&A using a rigless compaction process.

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APPENDIX B

Answers to Common Technical Questions and Concerns

Common Concerns and Questions

Oilfield Innovations have proven the concept[20] by compacting 2 $^{3}/_{8}$" tubing within 5 ½" API casing, as shown in Figure 13. The most common remaining questions and concerns are:

- How can Rigless Replace a Rig?
- What is Special about a Rig?
- How is Rigless Equipment Different?
- What does Thru-Tubing Mean?
- What does Wireline Look Like?
- What does Coiled Tubing Look Like?
- Above Seabed Equipment Removal?
- Does your Method work with Control Lines?
- How Much do you need to Compact?
- What about Helical Buckling?
- What about the Couplings?
- Oilfield Steel is too Strong!
- What about Integrity and Pressure Deration?
- Can you apply Sufficient Force?
- What about Different Tubing and Casing Sizes?
- Vertical Cutting Tools don't exist!
- Retrieval and Re-Entering Previous Cuts?
- You'd need a lot of Expensive Tooling!
- How does a Vertical Cutter Work?
- How does a Packer Enter the Casing?
- What about Packer Element Damage?
- How do you Clean the Casing?
- What about Piston or Casing Leakage?
- How about Hydraulic Piston Lock-up?
- What about Repairs Requiring Casing Milling?
- How about Cutting & Pulling Casing?
- Compare your P&A Method to Rig P&A!
- What about 500 Foot P&A Plugs?
- Upside Potential for your P&A Method?
- How Protected are your Patents?
- How can your other Patents Help?
- What is Abrasive Filament Cutting?
- How does a Wireline Fluid Motor Help?
- Patents for Thru-Tubing Logging? and
- Logging After Placing a P&A plug?
- Compare your method with Thermite P&A.

How can Rigless Replace a Rig?

Rigless methods use the in-situ tubing or coiled tubing to place P&A plugs, whereas rigs remove in situ tubing only to replace it with drill pipe and small diameter stingers that place P&A plugs. There are caveats for using in-situ tubing, coiled tubing or drill pipe to place quality P&A plugs, but each can place a quality P&A plug. The rest of P&A is a matter of logistics.

Figure 18 compares the various aspects of the P&A Process for our "rigless" method and that of a drilling or workover "rig." A fundamental technical difference is pressure contained spooling operations of rigless P&A (Figures 21 and 22) compared to jointed pipe hoisting and torque operations performed by rigs (Figure 19).

Rigs use an open vertical pipe (riser) to separate a fluid column containing well pressures from atmospheric and subsea environments, whereas rigless P&A uses a closed pressurised tube (lubricator or stripper) separating well pressures from atmosphere and subsea environments.

Rigs' built-in high capacity jointed pipe hoisting and torque equipment pass through a riser filled with heavy fluids controlling downhole pressures, whereas rigless wireline and coiled tubing use high speed spooling of a continuous string of wire or tubing that passes through the seals of a lubricator or stripper and in-situ production equipment.

Rig-based P&A must initially use rigless pressure containment, or risky snubbing operations that force jointed pipe into a well under pressure, to plug the well and establish a weighted fluid column to hold (kill) well pressures before replacement of the production tree with a blowout preventer (BOP) and riser (Figure 20).

High torque capabilities and fast jointed pipe lifting capacities of rig-based systems can be used where possible but are not necessarily advantageous when practitioners have developed alternatives like Perf & Wash that can replace milling or cutting and pulling casing.

Large capacities for storing and pumping fluids during various operations, including Perf & Wash, can generate unnecessary waste and additional disposal costs because disposal costs are less than the drilling rig time cost of minimising waste.

Oilfield Innovations method uses Figures 21 or 22 rigless equipment to cut tubulars and place a piston to compact LSA contaminated production equipment downhole to create a window for logging measurements that can reduce or remove the legal liabilities of P&A.

Oilfield Innovations method can use Light Well Intervention Vessels (LWIV) depicted in Figure 23 with rigless equipment like wireline and coiled tubing to set P&A plugs and repair

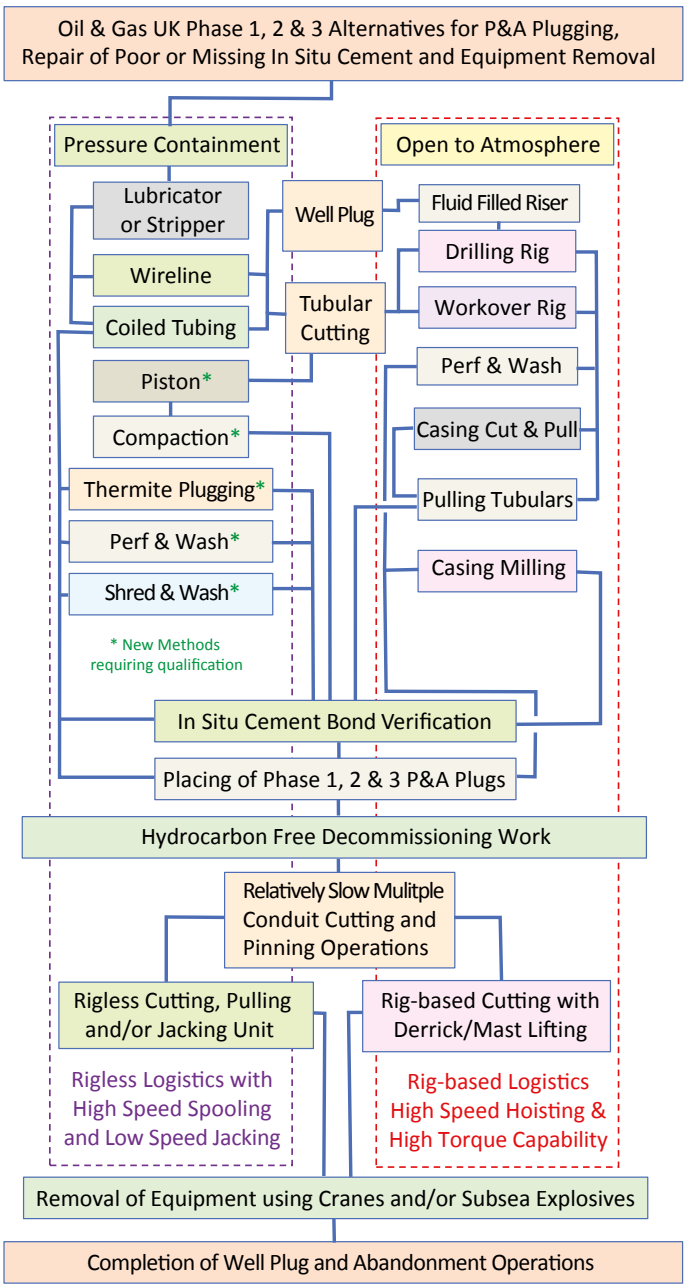


Figure 18- P&A Process Overview

cementation with rigless methods like Perf & Wash and/or our Shred & Wash method.

Alternatively, with respect to Figures 59 and 60, Oilfield Innovations space creation can provide logging measurements and remove annuli welding gaps that allow pyrotechnic methods like thermite welding of a self-sintering ceramic P&A plug (Lowry, 2015)[31].

Once P&A plugs are in place, offshore and subsea facilities are considered hydrocarbon free and rigless jacking and pulling equipment shown in Figures 24 or 25 can be used to lift production trees, wellheads, conductors and casing for pinning and transportation to shore for disposal.

Where conductors and casing cannot be lifted or jacked, platform removal equipment or subsea explosives are used

to extract the conductors, regardless of whether a rig or rigless method is used.

Apart from high torque and high speed jointed tubular lifting, rigless equipment can perform any P&A task performed by a drilling or workover rig.

What is special about a Rig?

Drilling rig are designed for "drilling" and constructing wells. Large workover rigs are designed for working over wells to, for example, replace the tubing or "drill" smaller hole sizes when side-tracking a well. Large workover units are typically referred to as a rig, whereas small jacking and pulling units are generally referred to as rigless. The distinction can be confusing.

The real distinguishing characteristics of "rig" relative to "rigless" comprises large high-speed hoisting and torque capacity as illustrated in Figure 19.

Drilling rigs only use +/-25% of their equipment during P&A because time consuming and expensive torque operations like milling are avoided wherever possible while high speed lifting operations are less applicable to P&A than drilling.

Additionally, rigs perform work with the well open to atmosphere.

Rigs and special snubbing units can strip larger diameter pipe connections into a well by opening and closing blowout preventers around the tubular bodies as the string is pushed into a pressurized well, but the activity is one of the most dangerous in the industry and generally avoided.

As snubbing is universally avoided where possible, rigs also have the distinguishing characteristic of working with the well open to atmosphere and depending upon a weighted fluid column for control of well pressures.

While that is not necessarily a problem when constructing a well it can be troublesome during P&A because in situ equipment controlling well pressures must be removed as shown in Figure 20 and the stability of a weighted fluid column is often difficult to maintain during P&A.

An unstable weighted fluid column can be very expensive because all rig-based P&A work must stop until the well control fluid column is made stable.

Additional well control costs of maintaining a stable fluid column, above those necessary to replace the production tree with BOPs, are relatively common during rig-based P&A. It is relatively common to have a fluid influx when perforating casing during P&A because an expected pressure or fluid imbalance was encountered outside of the casing being perforated.

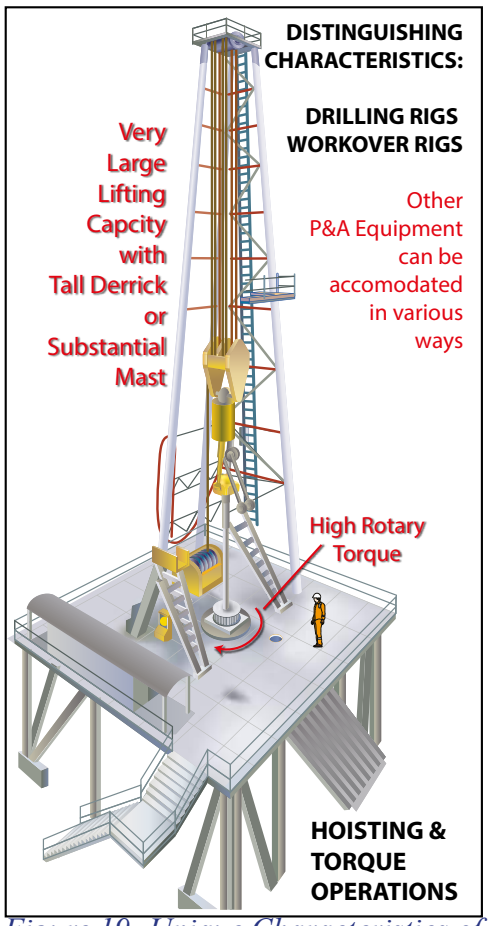


Figure 19- Unique Characteristics of Rig base P&A Equipment

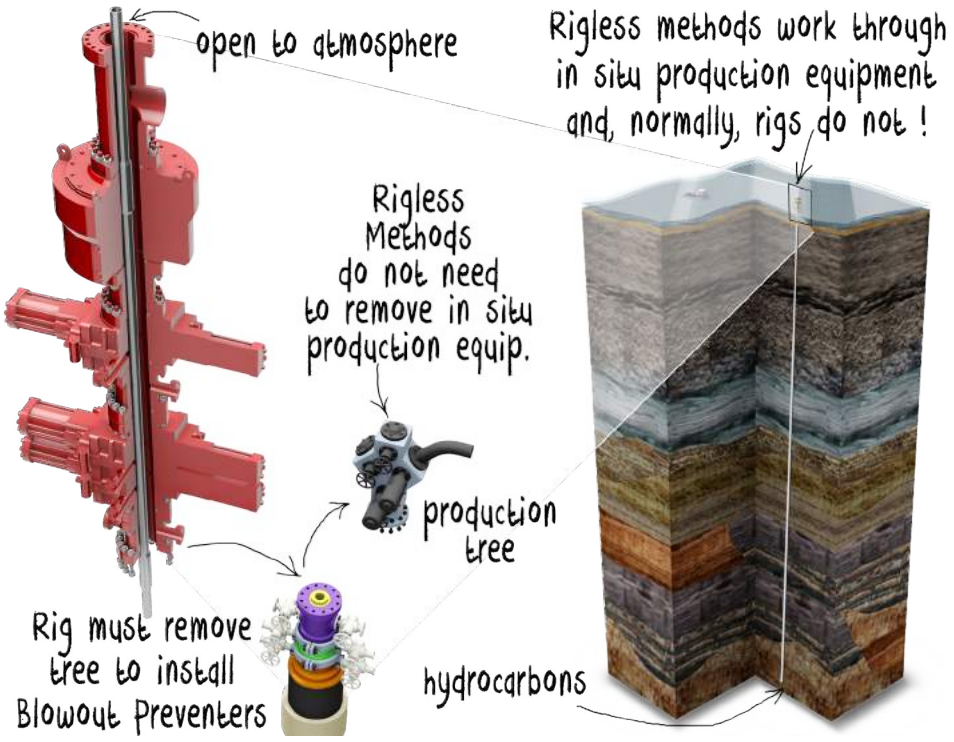


Figure 20- Unique Characteristics of Rig based Well Control

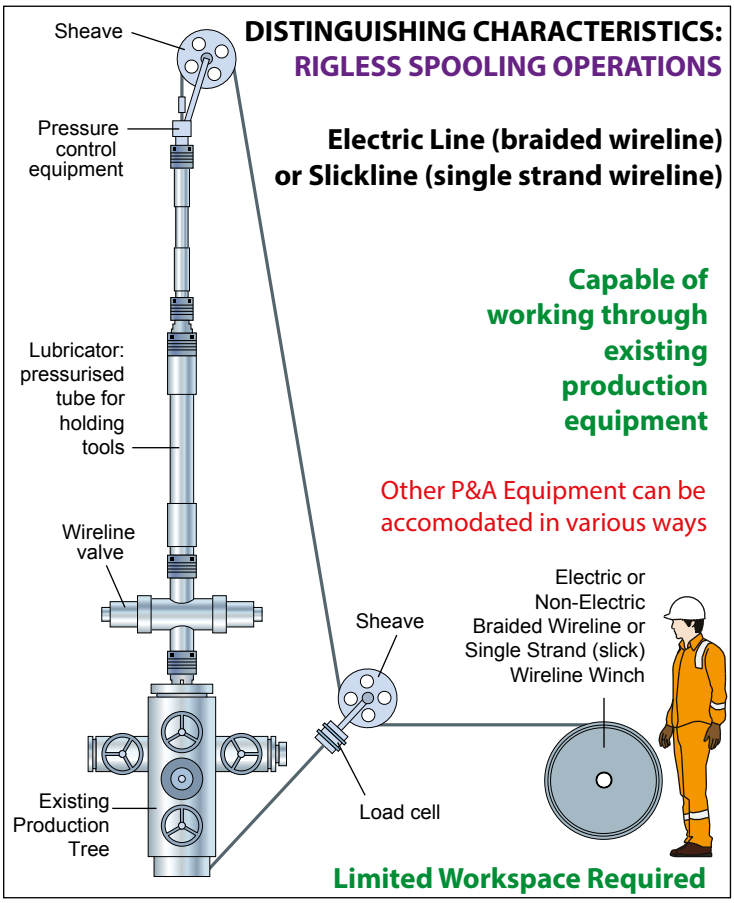


Figure 21- Unique Characteristics of Rigless Wireline (single strand and braided cable)

How is Rigless Equipment Different?

Rigless well intervention equipment involves high speed spooling of a continuous string used in platform and subsea operations as shown in Figures 21 to 23. Rigless jacking and pulling units, shown in Figures 24 and 25, can jack or pull tubulars from a well after it has been plugged and, preferably, after the well is considered hydrocarbon free.

Figure 21 depicts wireline tooling using single strand (slickline) or braided-strand (cable) wire operations having non-electric bare wire or electrical core insulated wire. Gravity is used to deploy tools while wire is spooled from a winch through wheels and pulleys that measure distance and line pull until it reaches a stuffing box or grease head seal at the top of a lubricator (tube for holding tools). The lubricator is attached to blowout preventers which are attached to in-situ production equipment.

Figure 22 illustrates coiled tubing, which is like single strand wire (slickline) with the except a larger diameter and an internal passage for pumping fluids. The larger diameter of the coiled tubing requires an injector head push or pull the tubing within a well, whereby a stripper seal is used to prevent escape of well pressures as tools are spooled in and out of the well.

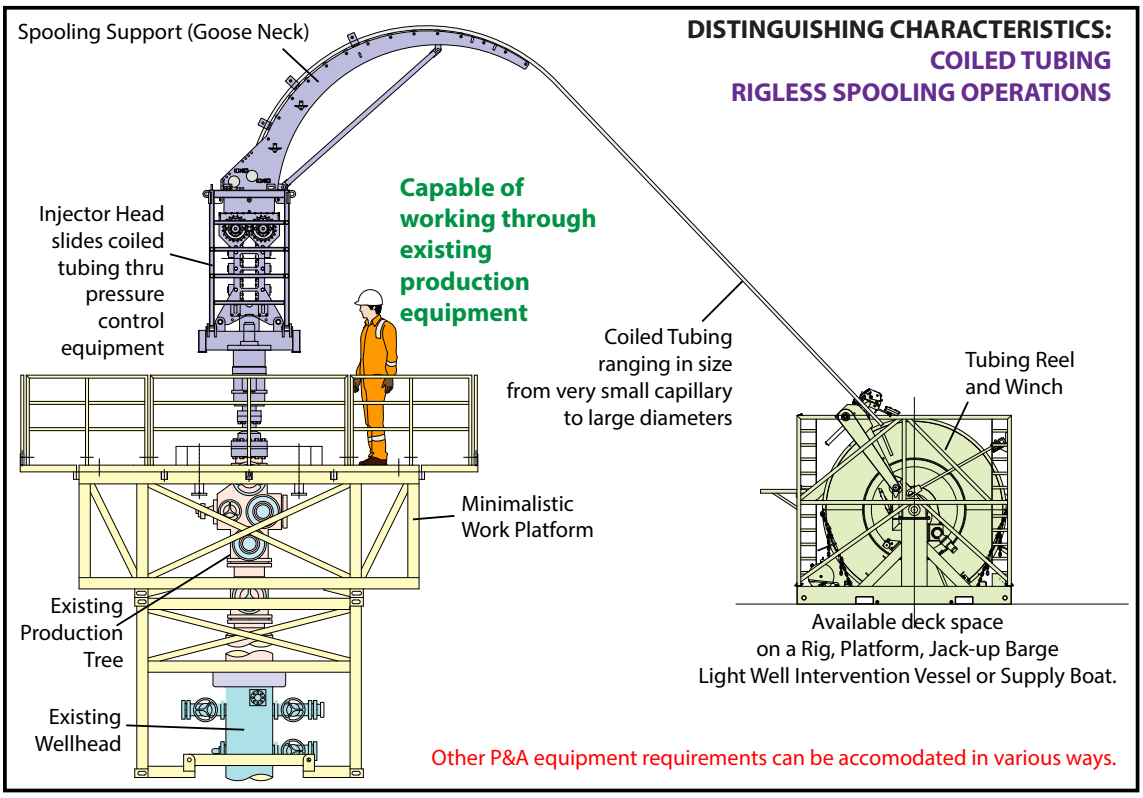


Figure 22- Unique Characteristics of Rigless Coiled Tubing

Both Figure 21 wireline and Figure 22 coiled tubing can be used with a subsea lubricator attached to a subsea well from the Light Well Intervention Vessel depicted in Figure 23.

Jacking and Pulling Units (JPU) pictured in Figures 24 and 25 must be assembled on a platform to jack or pull tubulars using the platform as support. Light Well Intervention Vessels (LWIV) depicted in Figure 23 can use the buoyancy of the vessel to pull production trees, wellheads and severed casing from the seabed.

The combination of rigless equipment shown in Figures 21 to 25 have been used to perform many well plug and abandonments and, when combined with other decommissioning activities, can reduce the P&A cost by at least 32% (Siems, 2016)[21].

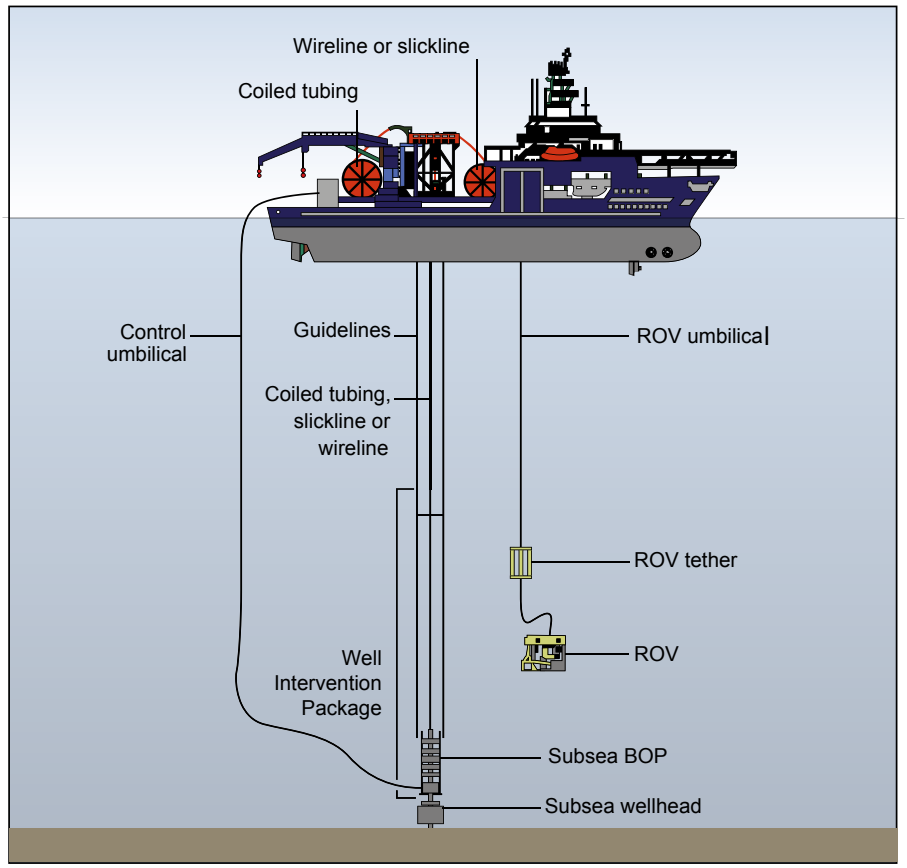


Figure 23- Rigless Light Well Intervention Vessel (LWIV) Equipment (Schlumberger)

Figure 24- Rigless Jacking Frame (Franks Intl.)

Figure 25- Rigless Jacking Pulling Unit (JPU) Equipment (Canny, 2017)[17]

What does Thru-Tubing Mean?

"Thru-tubing" indicates that small tools and a deployment string are passed through the production tree and tubing shown in Figure 26, whereas the tools of a "rig" are too large and must be deployed on pipe with enlarged connections that inhibit and effectively prevent fixed seals from isolating well pressures.

Except for small jacking and pulling units (Figures 24 and 25) rigless operations (Figures 21 to 23) work "thru-tubing," i.e. through the smallest internal diameter of the tubing and associated completion jewelery, whereas rigs must remove the Figure 26 tree and replace it with a blowout preventer (Figure 20) prior to removing the tubing. The single exception is a horizontal subsea tree where the tubing can be pulled through the main valve block of the subsea tree.

Figures 27 and 28 illustrate how Figure 21 rigless wireline equipment is rigged up on top of the offshore platform production tree in Figure 26.

Figure 26 illustrates the internal components of a surface (dry) production tree and wellhead. Apart from B and C annuli access, subsea horizontal trees have the same basic components and flow paths. Subsea trees do not typically provide either B or C annulus access and cement from an inner casing string is not normally placed within the previous casing to prevent trapping fluids within annuli.

For both dry and wet (subsea) trees, access to the "A" annulus is typically sufficient to riglessly set the two primary P&A barrier plugs.

Rigless P&A can use the flow paths shown in Figure 26 to circulate fluids and cement into the well using the in-situ equipment and tubing.

Surface trees are relatively straight forward with access to all annuli, whereas working with subsea well equipment is more complex for both rigs and rigless operations.

The tubing is landed in "horizontal" subsea trees, whereas the tubing is landed in the wellhead below "vertical" subsea trees. Drilling rigs can pull the tubing through a horizontal subsea tree but must remove a vertical subsea tree to pull the tubing. The "A" annulus access in a "vertical" subsea tree passes through the tubing hanger, whereas "A" annulus access passes through a "horizontal" subsea tree's primary valve block.

Differences in cement placement and annulus access cause differences in how P&A well control and cement placement is approached. With annulus access, cement can be circulated through in-situ tubing and annuli, whereas an inability to circulate through annuli dictates using rigless coiled tubing.

A rig and rigless subsea annulus is accessed using a remote operated vehicle (ROV) to connection jumper hoses to the annulus, whereas the bore of subsea trees can be accessed by either floating drilling rigs or Light Well Intervention Vessels in deeper water depths, while shallower water depths require either jack-up drilling rigs cantilevered over the tree or an overboard jack-up barge crane supporting rigless subsea well

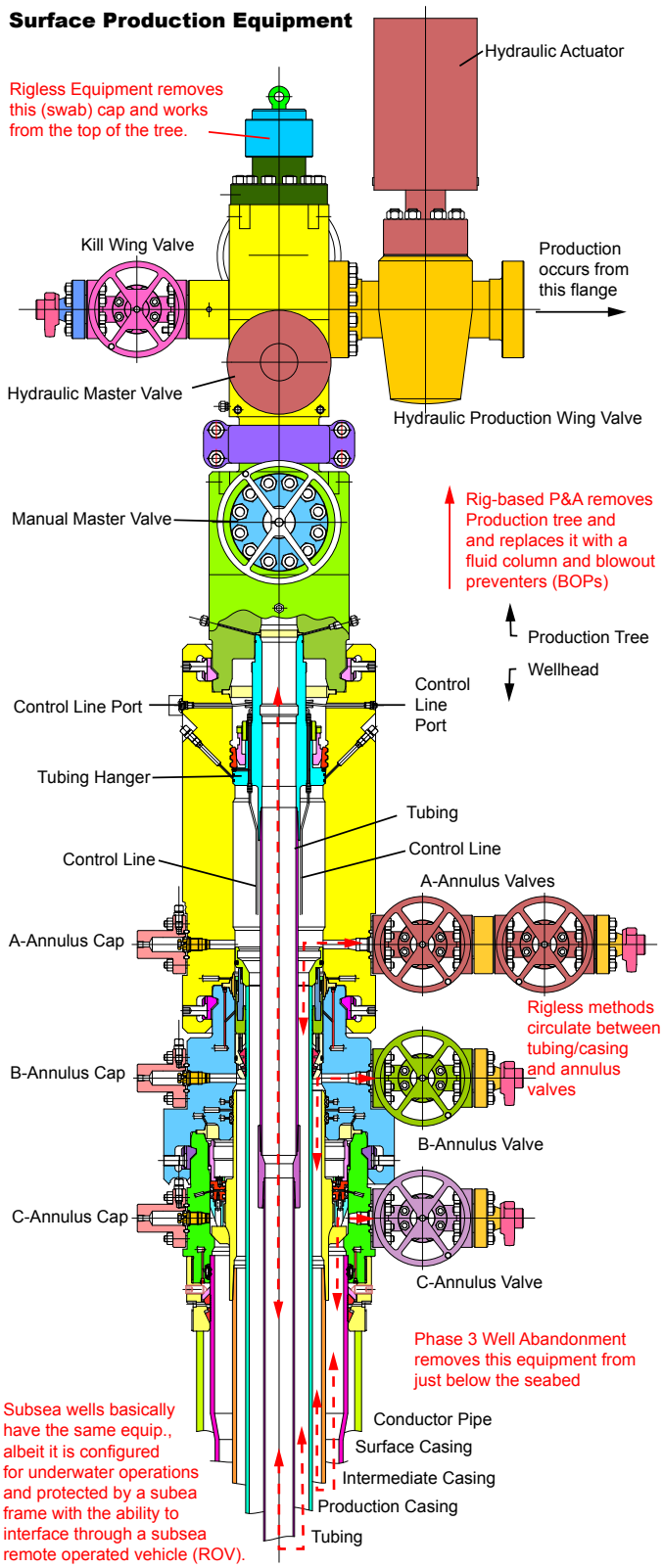


Figure 26 - In Situ Surface Production Equipment

control tooling attached to the subsea tree.

A primary P&A cement plug can be set through dry or wet production trees using a specialized wireline-set packer as a base and wiper plugs installed on a specialized spool piece to isolate the cement and indicate completion of the job (Olsen, 2017)[105]. This rigless operation is often performed on rig-based P&A prior to the Figure 20 removal of the Figure 26 production tree.

Figure 27- Rigless Slickline / Wireline Mast, BOPs and Lubricator Rig-up

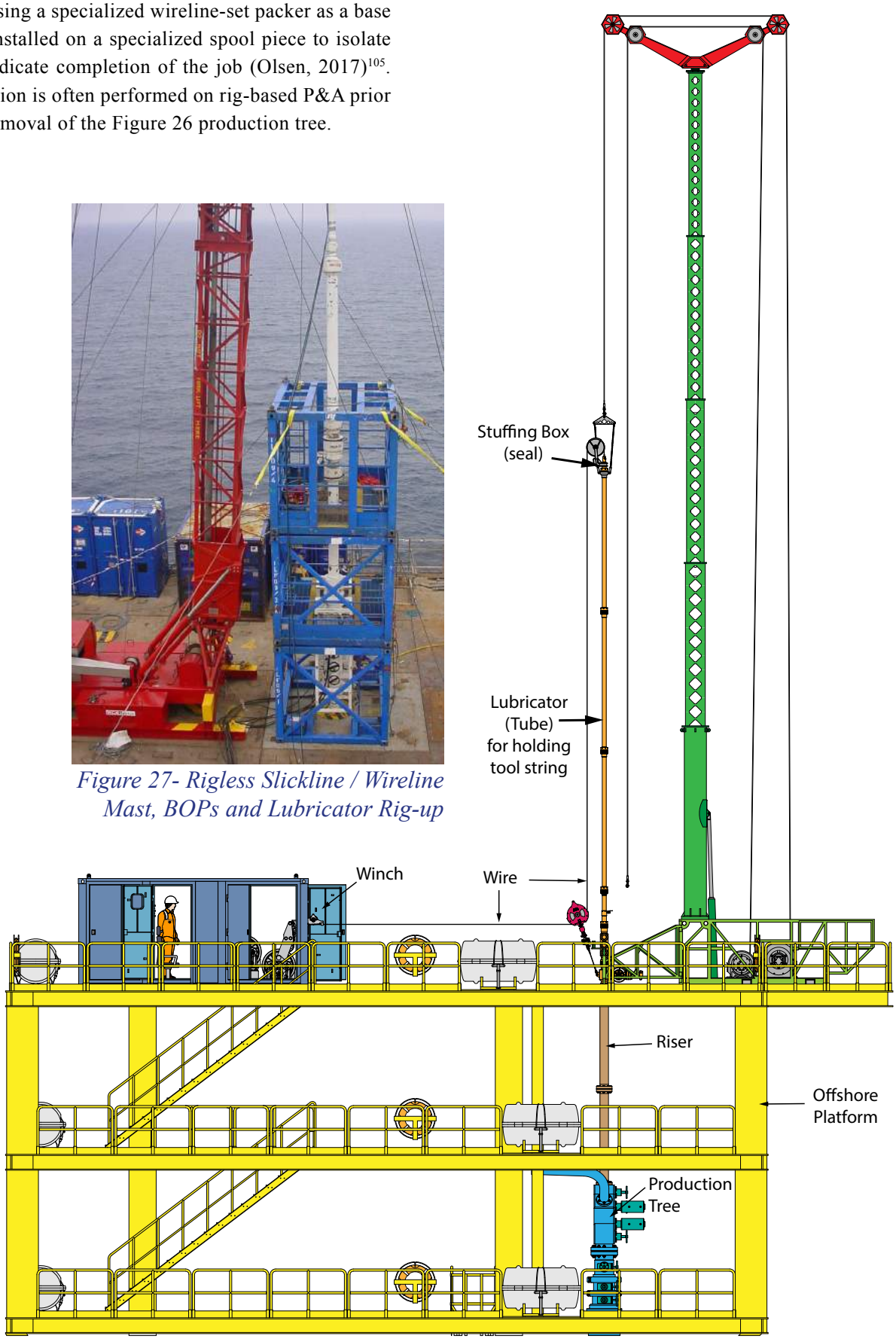


Figure 28- Rigless Slickline and Wireline Equipment Rigged-Up on Small Platform

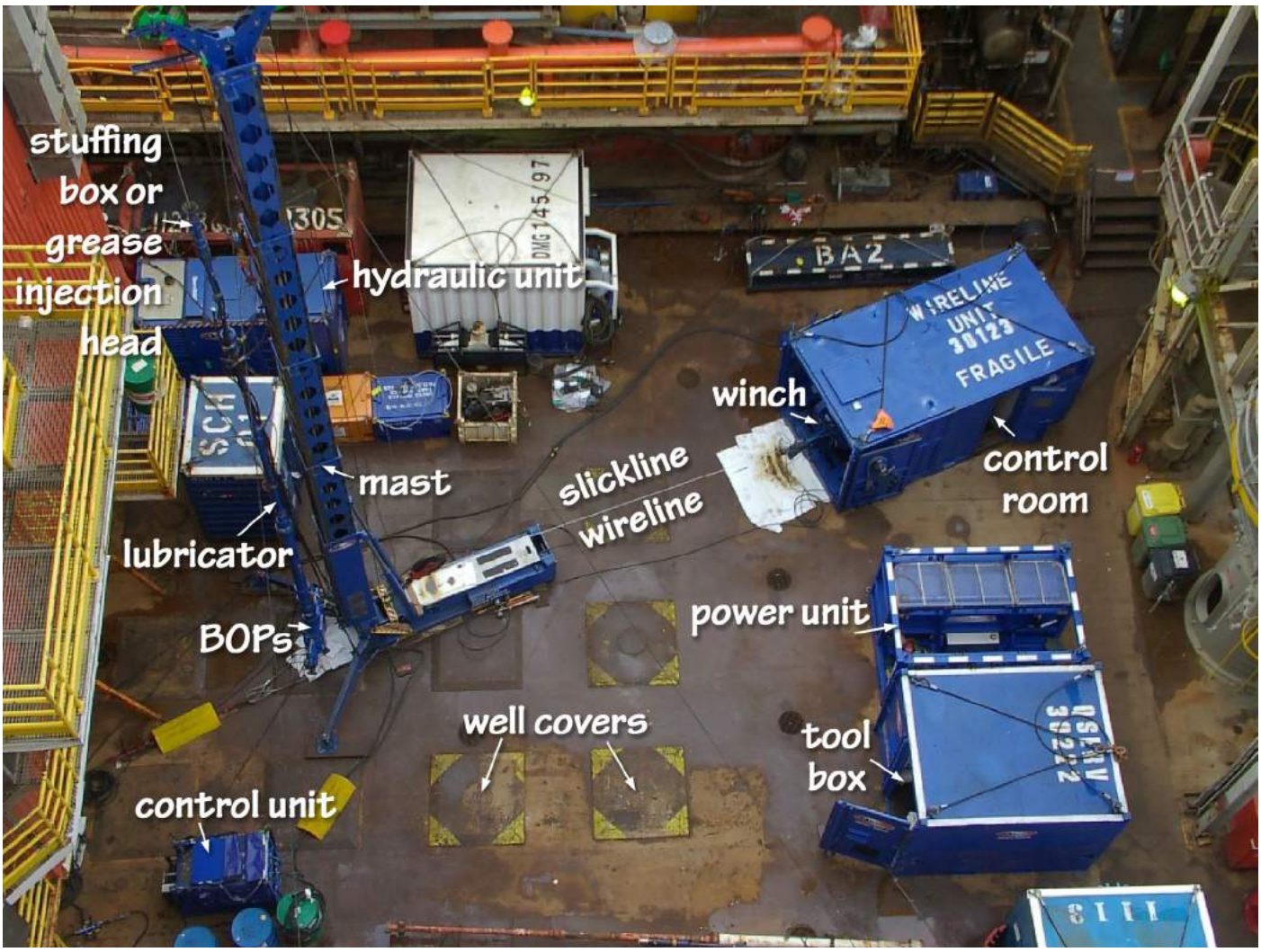


Figure 29 - Slickline / Wireline Equipment (Wright, 2011)[67]

What does Wireline Look Like?

Most people have seen pictures of a drilling rig in the press or films[23,24], whereas only practitioners can readily visualise wireline equipment shown in Figures 21, 27 to 29 and 42.

The photo of Figure 29 (Wright, 2011)[67] looks downward upon wireline equipment (painted blue) placed on the deck of an offshore platform. The round shapes on the platform deck are access covers above each of the platform's wells.

The Figure 29 control room wireline unit houses one or two people operating the wireline winch. The winch can use either single strand wire (slickline) or multi-strand wire (braided), wherein both types are referred to wireline. When electric conductance insulated wire is used with single or braided wire, electrified braided wire is referred to as "electric-line" or "e-line" while single strand mono core electric wire is referred to as "digital slickline (Loov, 2015)[82]." Regardless of the type, wire passes across wheels and through pulleys that measure distance and line weight between the winch, mast and stuffing box or grease injection head as shown in Figure 21.

The difference between non-electric and electric wireline is primarily the pulling and jarring capacities of the wireline string. Immersing electrified wire into a liquid filled well requires isolation between fluids and electrical power that limits the pulling and jarring capacities lest the insulation become damaged.

Non-electric wireline rigless tooling can use battery powered tools together with hydrostatic pressure, shear pins and springs for actuation and deactivation, whereas digital slickline and e-line can actuate and deactivate tools real time via an electrical current passed through the wire.

A stuffing box is a stripper seal for smooth single strand wire (slickline), whereas a grease injection head is needed for sealing around the irregular curvature of braided wire.

Either a stuffing box or grease injection head will create a seal around the wireline at the top of the lubricator, which is just a pressure containment tube that holds small rigless tooling that can pass thru-tubing.

The lubricator can be connected to and disconnected from blowout preventers (BOPs) to load tools attached to the end of the wireline.

Figure 30 - Rigless Coiled Tubing on Limited Space Small Platform (Sundramurthy, 2014)[45]

The hydraulic unit powers the control unit and mast which is a portable crane used for lifting and lowering the lubricator to load and unload tools to and from the lubricator tube while BOP or valves of the well are closed. Once the lubricator loaded with tools and attached to the BOPs and pressure tested, the valves and BOP are opened to well pressure and the winch hoists tools into and out of the well using wire.

Wireline can be used with or without a rig and it is easy to see why wireline is the lowest cost rigless well P&A equipment when you compare its size in Figure 29 to that of the drilling rig in Figure 2.

What does Coiled Tubing Look Like?

Coiled tubing is slickline with a hole in it (Carl Lawson, Phillips 66). Figures 30 and 31 show coiled tubing equipment with small and large foot prints, while Figure 32 shows a close-up view of an injector head which differentiates coiled tubing from other rigless spooling equipment.

Coiled tubing comes in capillary sizes from ¼ inch (6.4mm) to ¾ inch (19mm) outside diameter, used primarily in downhole chemical treatments, and larger 1 inch (25.4mm) to 3 ½ inch (90mm) outside diameters for other applications.

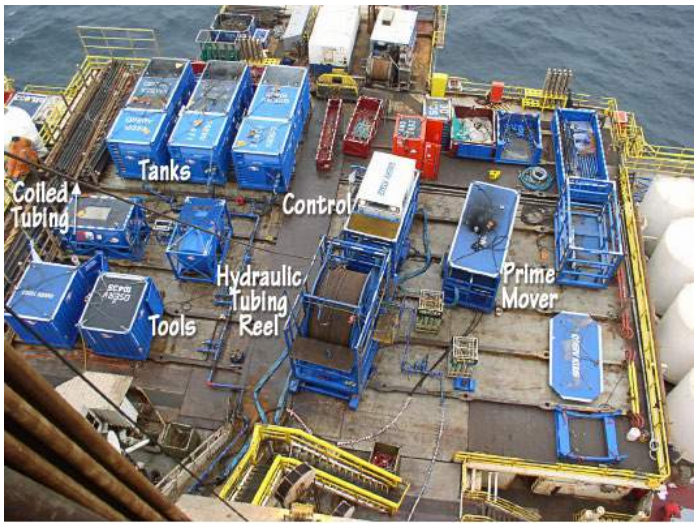


Figure 31 - Rigless Coiled Tubing on the deck of a Drilling Rig (Wright, 2011)[67]

Capillary coiled tubing provides an advantage over larger coiled tubing due to its lighter weight, smaller footprint, mobile structure, faster running speeds, and more economical costs, albeit friction pressures when pumping abrasive fluids can be limiting. Capillary tubing used for P&A in some remote onshore coal bed methane wells (Wilde[92], 2013)[92] can use Fly Ash Geopolymer Cements (Salehi, 2017)[122] applicable to North Sea P&A.

Small coiled tubing equipment packages are comparable to more conventional larger spreads. A small coiled tubing package can be lightweight with a small-footprint which is especially beneficial where challenging crane or deck space limitations exist. The application of small coiled tubing units can substantially reduce costs, logistical support and risk exposure (Sundramurthy, 2014)[45].

As shown in Figures 30 and 32, a reel can deploy coiled tubing through an injector head that pushes the continuous tubing through a stripper element that closes around the coil's smooth outer surface to create a seal between well pressure and atmospheric or subsea environments.

Because rigs cannot work effectively through pressure containment, coiled tubing is often placed upon the deck of a drilling rig for well operations through the well's in-situ production equipment, as shown in Figure 31.

A prime mover supplies power to the control system that hydraulically operates the reel (winch) that spools a continuous tubing string into and out of the injector head and stripper seal connected to in-situ production equipment. Coiled tubing tanks and pumps can circulate fluids through the coiled tubing when it is moving or stationary.

Oilfield Innovations' method can use conventional coiled tubing P&A techniques for wells suffering from sustained casing pressure in one or more annuli. Abrasive jets can cut

holes into casing(s) across a full circumference of the casing, i.e. 360 degrees. An assembly can then be run on coiled tubing and rotated using an indexing tool followed by retainer plugs and squeezing of sealant behind the casing to stop the sustained casing pressures (Zwanenburg[94], 2012; Tanoto[109], 2017).

Where LSA scale inhibits through tubing access, coiled tubing can drill a pilot hole and use a scale-removal tool that jets beads to remove scale and provide access (Birk, 2013)[95].

Coiled tubing is particularly useful in Phase 1 and 2 P&A due to its: i) ability to carry out work in live wells with high wellhead pressures; ii) versatility to convey tools and fluids that are necessary to secure the well and prepare it for decommissioning; and iii) a compact footprint and minimal environmental impact as compared to a rig or a snubbing unit (Webb, 2014)[93].

Rigless coiled tubing equipment can be used from a platform's or a rig's deck, as shown in Figures 30 to 32, or it can be spooled from the deck of a jack-up barge to a platform which lacks sufficient space or to a subsea well in shallow water with a jack-up barge overboard crane supporting well control equipment.

Wireline and coiled tubing are regularly deployed from Light Well Intervention Vessels to access subsea wells in deeper water (Aguilar[46], 2009; Willis[75], 2013; Moeinikia[63], 2014; Locken[82], 2015; Gajdos[51], 2015).

Small capillary coiled tubing, using fly ash polymer cements, or larger coiled tubing units, using normal cement or other sealants, can perform P&A in very limited platform spaces or larger spaces associated with platforms, barges or boats.

Oilfield Innovations' method minimizes total P&A cost by first evaluating lower cost slickline or wireline with circulation through in-situ tubing. If circulating through in-situ tubing is not desirable, rigless small capillary diameter or more conventional diameter coiled tubing is used for P&A, wherein coiled tubing is substantially less expensive than rig-based P&A and still capable of providing a 30% to 60% P&A cost savings.

Figure 32- Coiled Tubing Injector Head on a Platform

Above Seabed Equipment Removal?

Figure 33 depicts the removal of a conductor from the UK SNS Horne Wren platform using a crane and the jack-up barge in Figure 4. Figures 34 and 35 illustrate drilling and pinning of the Maureen Platform conductors and casings after they were cut with abrasive jetting (Phillips UK Ltd, 2001)[96].

Jacking and pulling units of Figures 10, 24 and 25 are not always necessary and conductors and casing can be removed with a crane, as shown in Figure 33.

Figures 34 to 35 pictures show that the cutting, pulling and pinning of conductors and casing can be a time-consuming task where avoiding the high hourly cost of a drilling rig is the most economic option.

Rigs can cut and pull casings and conductors one-at-a-time assuming they are not stuck in place by cement or debris or, alternatively, wait for rigless abrasive cutting of multiple conductors with subsequent drilling (Figure 34) and pinning (Figure 35); however, both options are expensive.

Regardless of whether rig or rigless means are used, it is often the case that various well conductors and casing cannot be pulled with either jacking or drilling rig lifting and must wait for platform removal equipment as was the case for some wells during Maureen decommissioning[46].

Accordingly, the removal of above seabed equipment is more economic when combined with other platform and subsea decommissioning activities.

Figure 33- Horne Wren Cond. Removal (Claxton)

Figure 34- Drilling Well Conductor for Pinning (Phillips UK Ltd,2001)[96]

Figure 35- Pinned Well Conductor and Casing (Phillips UK Ltd,2001)[96]

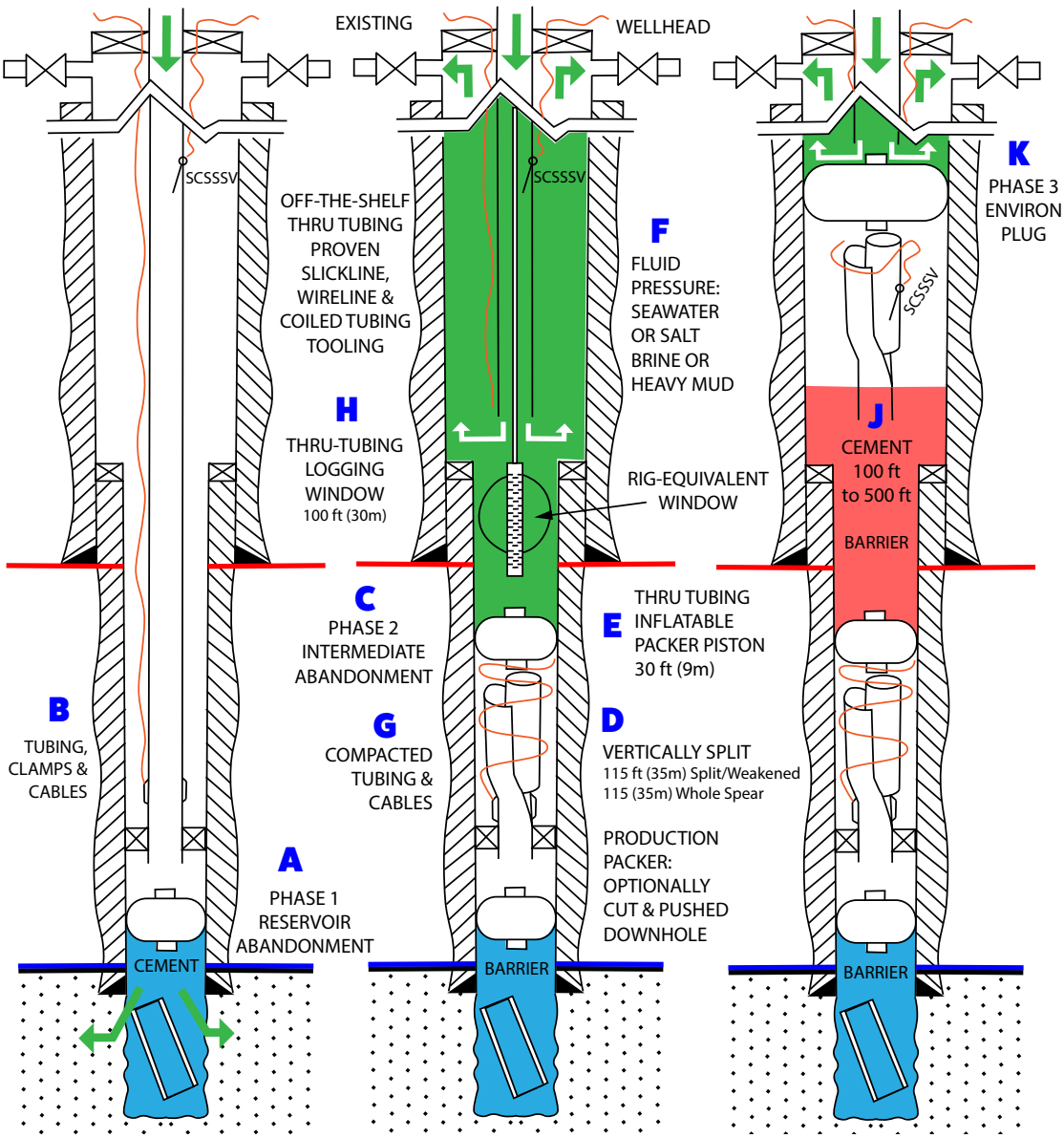


Figure 36- Compacting downhole Chemical Injection, Control Lines, Clamps and other Jewellery Downhole

Does your Method work with Control Lines?

Control and chemical lines are small, +/- ¼ inch (6.4mm) diameter, continuous capillary tubing or electrical cables attached to the tubing with clamps.

Various proven (TRL-7) knife and chemical cutters are capable of severing both tubing and associated small diameter lines clamped to the tubing's outer diameter.

Control and chemical lines can be cut with conventional knife cutters and compacted to remove them from consideration as shown in Figure 36, wherein a Rig-Equivalent-Window will provide the required length of good cement. Where a plug longer than the compaction window is desired, experiments by Aas[25], et al., show that embedding the control lines within the plug do not necessarily create a leak path. Also, fly ash geopolymer cement (Salehi, 2017)[122], which can be pumped through capillary coiled tubing, can enter open control lines.

If the compacted volume of control and/or chemical lines and associated clamps are a concern, additional tubing can be compacted to account for the additional debris.

Other completion jewelery, including the surface controlled subsurface safety valve (SCSSSV) can also be pushed into a well's lower end liquid spaces to provide an unobstructed logging and cementing space as shown Figure 36.

How Much do you need to Compact?

Good practice recommends logging at least 100 feet (30m) of in situ cement and, thus, a 100-foot (30m) logging window is needed.

Considering a compaction ratio of 50% and a 30-foot-long inflatable compaction piston, about 230 feet (100/0.5 +30), or 70 metres, of tubing would need to be compacted for each 100-ft logging window.

A 100-foot (30m) logging window can be formed by compacting an effective length of 115 feet (35m) of tubing spears into the 80%-90% liquid space around 115 feet (35m) of vertically split and weakened tubing.

For range 2 pipe, with an average length of 30 feet, 230 feet (70 m) of tubing is about eight (8) joints, wherein four (4) of the joints would be split and weakened with the other four (4) whole tubing joints used as spears. Range 3 pipe, with an average length of 41 feet, would result in three (3) joints being split and weakened with the other three (3) whole joints used as spears.

If clamps and control line debris is significant, an additional 30 feet (9m) could be added for such debris.

The math is simple and achieving a 50% compaction ration is visually evident in Figure 37. Finding 230 to 260 feet (70m-79m) of tubing adjacent to a formation with cap rock qualities within wells measured in thousands of feet or metres is normal practice within all P&A work scopes.

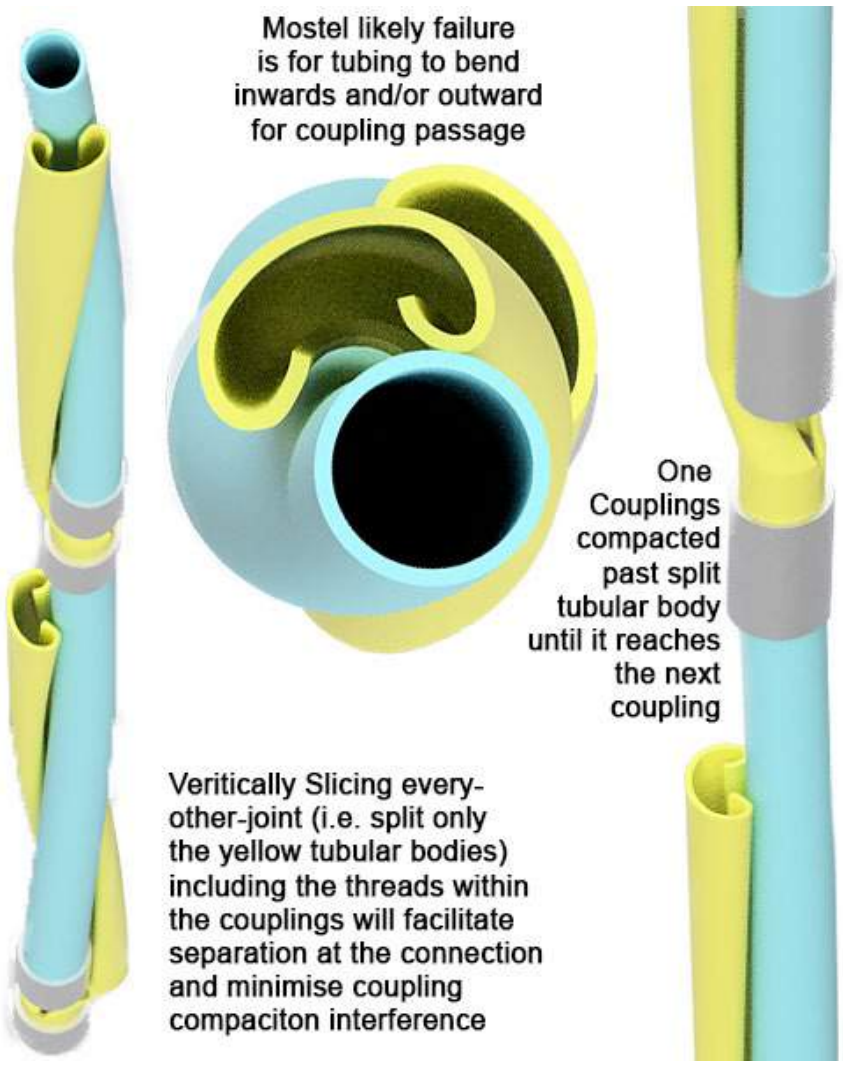


Figure 37- Vertically Slicing Every-Other Tubing Joint

What about Helical Buckling?

Pipe-in-pipe arrangements with tubular movement within casing is peculiar to subterranean wells and often contributes to misconceptions regarding the strength of oilfield steel.

Tubular buckling research (Wu[40], 1993; McCann[42], 1994; Hishida[41], 1996; Zdvizhkov[39], 2005, Michell[35-38], 1986-2006) demonstrates that helically buckling of pipe-in-pipe arrangements can exert very high frictional forces that can inhibit compaction of "whole" tubulars within other tubulars.

When whole tubing fails under axially compressive loads within casing, the failure tends to occur over a short axial distance because the friction of helically coiled and buckled tubing against the casing wall dissipates forces that might otherwise cause larger failures.

Buckling resistance is derived from a tubular's diameter, cross sectional area, second moment of the area (bending) and polar moment (torsion).

Splitting the tubing in step #1 of Figure 12, as shown in Figures 11 and 14, destroys the strength of its circular shape to substantially reduce area and polar bending moment resistance to facilitate bending shown in Figure 37 and allow side-by-side tubing compaction to achieve 50% compression.

What about the Couplings?

Unless downhole plasma cutting (Gajdos, 2015)[51] is qualified for vertical splitting, cutting through both the tubular body and coupling will be difficult due to the thickness of the combined wall and coupling. Development of a downhole plasma cutter is an alternative to developing the mechanical vertical cutter of Figure 44, albeit downhole plasma cutting is likely to have higher development and operating costs.

Vertical splitting of the tubing body, using Figure 44 tooling, can cut the threaded portion of the body such that the body will separate from the coupling during compaction.

Using thru-tubing casing collar locator (CCL) logging, the in-situ depth of tubular couplings can be determined and either Figure 38 or Figure 44 tooling can be hoisted between the couplings to vertically weaken or slice every other tubular joint to provide Figure 37 compaction.

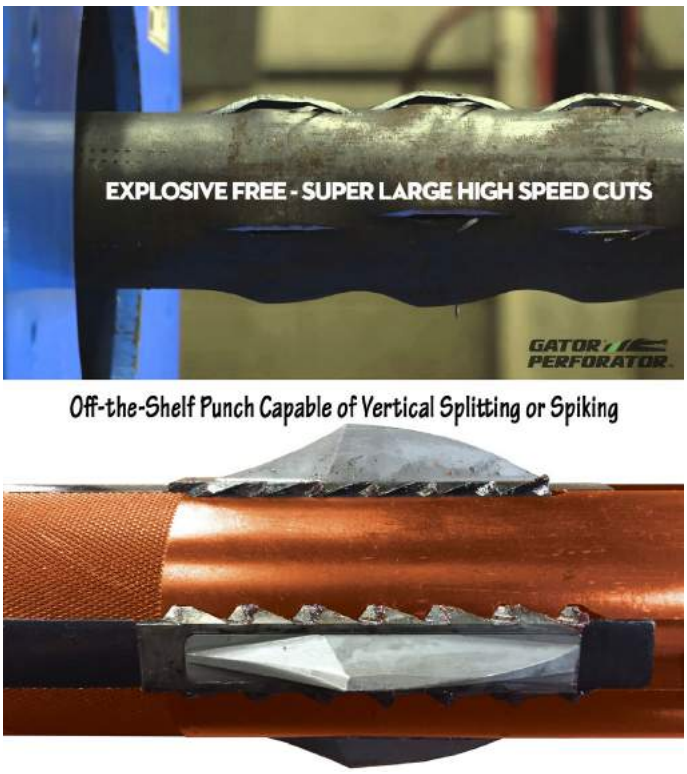
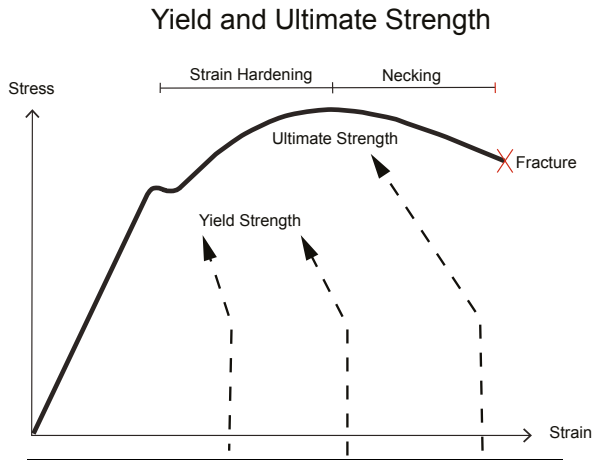


Figure 38- Gator Perforator® (Source: Website)



API 5CT - YIELDS			
	YIELD MINUMUM PSI	YIELD MAXIMUM PSI	ULTIMATE MINIMUM PSI
J-55	55,000	80,000	75,000
K-55	55,000	80,000	95,000
C-75	75,000	90,000	95,000
N-80	80,000	110,000	100,000
L-80	80,000	95,000	95,000
HC-85	85,000	100,000	95,000
C-90	90,000	105,000	100,000
C-95	95,000	110,000	105,000
HC-95	95,000	125,000	110,000
P-105	105,000	135,000	120,000
P-110	110,000	140,000	125,000
Q-125	125,000	150,000	135,000

Figure 39- API 5CT Steel Specification

Accordingly, by vertically slicing every-other tubular body, the tubular string can separate at each coupling and a whole tubular joint can push its lower end coupling to bend and pass by the split tubular body as shown in Figure 37.

Flaring or bending of a split and weakened tubular body either inward or outward facilitates passage of the coupling as shown in Figure 11 and Figure 37.

As described in Appendix A, Oilfield Innovations are presently working with OGTC, OGIC and the University of Glasgow to better understand how to best split and/or weaken the tubular bodies to minimise compaction friction associated with the couplings.

Oilfield Steel is too Strong!

Believing that oilfield steels are somehow stronger than other steels is a common misconception. The yield strengths of other steels are similar. Oilfield tubulars generally have a greater wall thickness that provides additional strength, but splitting tubulars reduces the required bending force dramatically.

Figure 38 shows a Gator Perforator® tool visually demonstrates that oilfield steel is not as strong as you might believe, wherein it can rupture tubulars by "pushing" sharpened spikes through the wall of tubing. Such a tool could be used to weaken tubing if Oilfield Innovations cannot find funding to develop the tooling in Figure 44.

Like the lower part of Figure 13, the upper part of Figure 39 shows the relationship of stress, strain and yield strengths, while the lower table lists the yield strength minimum and maximum values as well as the ultimate yield values for various API 5CT specification tubulars.

As shown in the table of Figure 40, forces applicable to a compaction piston will far exceed the yield of oilfield steel once it is cut and/or weakened.

Yielding cut and weakened tubing is not a possibility; given sufficient force, it is a certainty.

What about Integrity and Pressure Deration?

The integrity of old wells is a concern for continuing production but not necessarily P&A.

Firstly, wells with higher grades of steel will have higher pressure ratings and, thus, compaction pressures will be matched to the steel grades being compacted even when the well pressure ratings have been derated.

Secondly, as shown in the table of Figure 40, the required pressures are not necessarily onerous and heavy fluids can be used to lower necessary surface pressures during compaction within derated pressure envelopes.

	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

Figure 40 - Applicable Piston and Fluid Weight Forces

Finally, many old wells have leaking valves and seals that may need to be repaired or supplemented by, for example, pumping sealants into various voids and adding working valves to outside of valves which no longer work. Such costs are not necessarily significant.

It is important to remember that the objective of P&A is to "kill the patient" and not save it.

Integrity issues can be addressed at a relatively low cost for the remaining short life expectancy of the well, i.e. through P&A.

Can you apply Sufficient Force?

A geologic overburden normally has a water gradient which is assumed in the Figure 40 table of forces that can be applied to cut and weakened oilfield tubulars according to the piston's casing size, applied surface pressure and fluids within the well at a depth of 6,000 feet (1829 metres), which is a relatively shallow fluid column weight applicable to most UK North Sea secondary P&A plugs. Deeper P&A compactions will have larger forces with weighted fluids and deeper fluid column heights while shallower depths may use still heavier fluids to compensate.

Figure 14 illustrates how tubing can be split and weakened. Cutting and weakening can be used to reduce the applicable steel area to less than one 1 in^2 to more easily bend the walls of steel tubulars.

For arguments sake, assume the steel area resisting bending is 1 in^2. Comparing the Figure 39 maximum yield (95,000 psi) for common North Sea steel (L80) to the table of Figure 40 demonstrates more than adequate bending forces are available.

About 2000-psi surface pressure applied to sea water at a depth of 6000 feet in 9 $^5/_8$" casing will overcome the maximum yield of 1 in^2 of L80 steel and, thus, allow tubing compaction. If 11.6-ppg brine is used then a surface pressure of 1000-psi is needed and if 14-ppg water based mud (WBM) is used then a surface pressure of a few hundred pounds per square inch is needed to overcome the maximum yield of 95,000 psi for 1 in^2 of L80 steel.

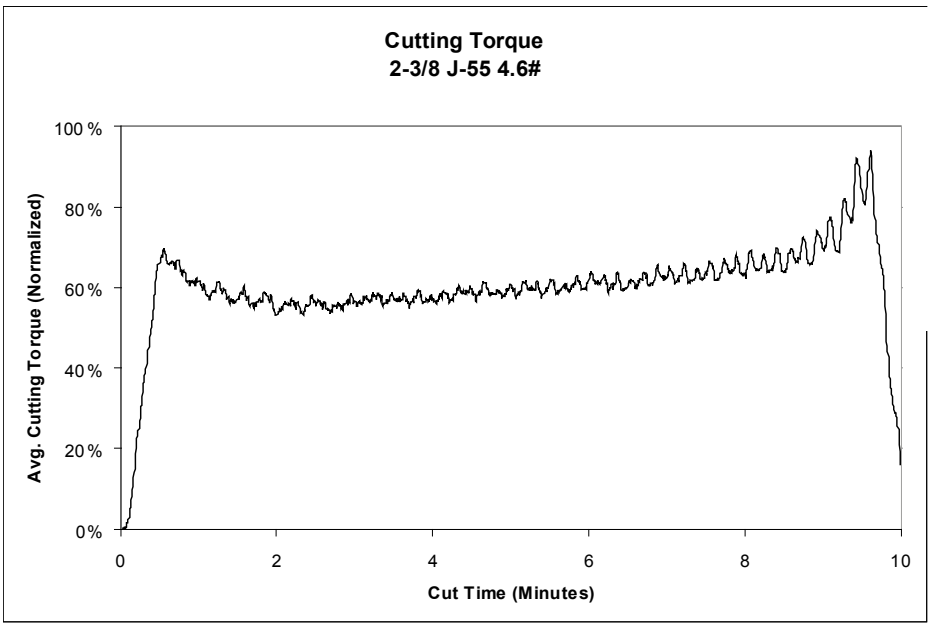
The math is simple, oilfield steel has defined properties, cutting tubulars reduces the steel area applicable to bending and the forces available to compaction are more than sufficient to yield oilfield steel.

What about Different Tubing and Casing Sizes?

Figure 40 provides applicable compaction forces for different casing sizes, wherein North Sea casing sizes provide excellent compaction force. The proportions of tubular combinations are standardised (see Figure 11) and even 9 $^5/_8$ casing could be compacted into 87% liquid space within 13 $^3/_8$ casing when split using the Figure 44 tooling and severed using an abrasive filament cutter (see Figure 54).

Oilfield Innovations have proved the concept (see Figure 13) under the worst friction and piston force conditions. Our simulations used dry friction in a horizontal orientation, whereas North Sea wells will be fluid filled and vertical or inclined with significantly less friction. Also, gravity will add the weight of the steel to place the maximum force as the bottom to further maximise compaction.

North Sea 7 inch 29-ppf, 9 $^5/_8$ inch 53.5-ppf and 13 $^3/_8$ inch 72-ppf casings have 167%, 319% and 667% larger piston area sizes, respectively, than the 5 ½" 20-ppf casing used in our proof of concept, while L80 and P110 grades used in the North Sea have maximum yields only 119% and 175% greater than the J55 tubing used in our proof of concept. Compared to our proof of concept, the increase in piston force is greater than the increased strength of 1 in^2 of steel.



Size (in.)	Weight (lb/ft)	Yield Strength (kpsi)	Approx. Cut Time (min)
2 3/8	4.6	55	10
2 3/8	4.6	110	25
2 7/8	6.5	80	25
2 7/8	7.9	110	60

Figure 41- Downhole Cutting Wheel Performance (Campbell, 2009)[130]

More than enough liquid space exists within the casing and defined properties of API 5CT tubulars are exceeded by applicable piston forces shown in the table of Figure 40.

Vertical Cutting Tools don't exist!

The proven Gator Perforator® shown in Figure 38 may be used to weaken tubing sufficiently that it could split along perforations to effectively shred tubing vertically.

Because the Gator Perforator® is not able to create a single split in tubing and cannot reach casing to enable casing compaction or Shred & Wash cement repair, Oilfield Innovations believe the tooling of Figure 44 should be developed, wherein Figure 41 proven cutting wheels technology is hoisted with the tooling of Figure 42.

Following OGTC and OGIC simulations described in Appendix A, Oilfield Innovations require support to develop a method of deploying proven tubular cutting wheels shown in Figure 44 or qualification of the Gator Perforator® with Figure 42 conventional wireline equipment.

As shown in Figure 41, cutting wheel experiments (Campbell, 2009)[130] for J55 through P110 grade steel for 2 $^{3}/_{8}$ inch and 2 $^{7}/_{8}$ inch tubulars found that the average required force is relatively constant and cutting times vary according to the steel grade and wall thickness.

Oilfield Innovations have also proven the concept of cutting 5 ½" 20-ppf L80 tubulars with similar low cost cutting wheels available off-the-shelf from ordinary hardware stores. We severed a 5 ½ inch 20-ppf L80 tubular joint, "by hand," with a conventional plumber's cutting tool in about 300 rotations with no measurable wear to the cutting wheel.

Cutting wheels like that of Figure 41 can be very low cost and the required deployment tooling is limited to a few hand sized tools using mechanisms like the Figure 43 gauge hanger. Both cutting wheels and the gauge hanger deployment mechanisms are proven. Oilfield Innovations simply want to qualify the combination of these two proven technologies.

Retrieval and Re-Entering Previous Cuts?

If for any reason the tools are pulled, they can be rerun to re-enter previous cuts. For example, if operations are to be stopped due to daylight hours, incoming weather or should the Figure 41 cutting wheels dull and additional cutting is required, the wheels can be replaced and/or the tool rerun later.

The left of Figure 14 depicts gravity orientation of the tool body deploying a cutter skate for splitting and weakening tubulars. Gravity orients one or more aligned skates upward to the same groove each time it is run.

The right of Figure 14 illustrates that phasing of the cutters creates a stacked helical arrangement of cutting skates, wherein gravity acting on the unsupported parts of the tooling naturally urges the skates in a helical path when moved along the axis of the well and hoisted up or down.

If for any reason the tooling is pulled to surface before cutting through the tubular wall, when the tool is rerun gravity will orient the tool and naturally rotate it, as it is hoisted, until it falls into the previous cut grooves where the spring force on the skate cutters and sides of the grooves will hold it within the same cuts.

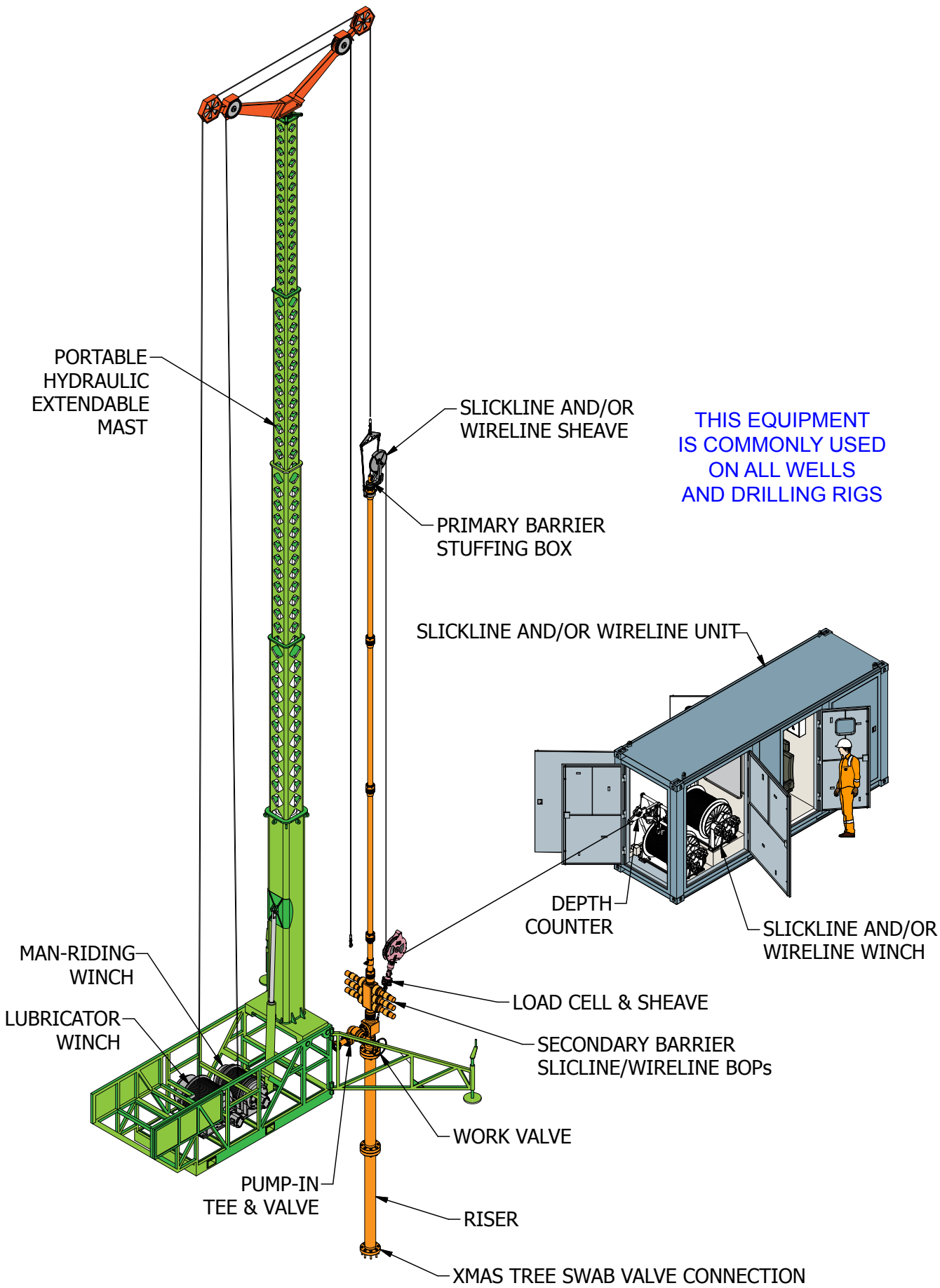


Figure 42- Rigless Mobile Single Strand (Slickline) and Braided Strand (Wireline) Equipment

You'd need a lot of Expensive Tooling!

As shown by the soft-drink-can-scale in the lower left of Figure 44, the tooling is relatively small with a 2.36-inch (60mm) diameter and can be combined with proven tooling that already exists for rigless wire and coiled tubing deployment.

To minimise development and ultimately operating costs, Oilfield Innovations have designed a single small diameter tooling set applicable for vertically cutting API specified OCTG tubulars from 3 ½" inch (88.9 mm) tubing to 9 5/8 inch (244.5 mm) casing and use proven mechanisms like cutting wheels and gauge hanger skate deployment.

While nothing in the oilfield is cheap, our tooling will be at the bottom of oilfield tool development cost rankings.

How does a Vertical Cutter Work?

The Figure 41 cutting wheels are deployed on skate's body like the slips on the Figure 43 gauge hanger, whereby skates are extended then hoisted up and down by the Figure 42 wireline tools deployed through in situ production equipment.

The tools function like ice skates or roller skates with sharp edges that are pushed and pulled across ice or flooring to cut a groove and deepen the groove until the ice or flooring are completely cut.

We propose qualifying basic tools that use sliding shafts, springs and shear pins, which are the simplest and most reliable mechanisms in the oil and gas industry.

Alternatively, if funding is not found, we could qualify the Figure 38 Gator Perforator®.

Figure 44 illustrates a single vertical cutter tool string with a single skate cutter tool (07) deployed in three different positions A), B) and C). Figure 44 also depicts tool subassemblies (01) to (10).

Figure 44 has a single skate subassembly (07) carrying three cutting wheels usable to split and weaken the tubing in step#1 of Figure 12.

Multiple vertical skate cutters subassemblies (07) can also be stacked and either aligned or phased, as shown on the far left and right sides of Figure 14.

Figure 44 deployment position A), cutting position B) and retrieval position C) use proven TRL-7 subassemblies 01 to 05 while subassemblies 06 to 10 are new tools to be manufactured and qualified.

Funding is needed for the construction and qualification of new components comprising Figure 44: spring drive (06), vertical skate cutter (07 extended & 09 retracted), a telescopic spring release (08) and an adapter (10) for connecting to other tools.

Figure 44 position A) illustrates the cutter in a retracted position that is lowered into the well on wire attached to the rope socket (03). Tools are guided over any upsets within in situ production equipment using the roller stem (04) wheels and knuckle jar (01).

A hydrostatic actuator (02) is programmed to measure the hydrostatic pressure and temperature for actuation after a specified depth has been reached and a specified time has elapsed.

Figure 44 position B) illustrates firing of the first hydrostatic actuator (02) at the desired depth to cock a spring tool (06) that drives an internal shaft to apply a constant force that deploys and holds the skate's cutting wheels against the tubular wall.

Engaging the skate cutting wheels against the tubular wall, then hoisting the skate up and down on a wire, cuts the tubular's inner wall vertically until a second programmable hydrostatic actuator (02) fires.

The second actuator is used to shear pins in the telescopic tool (08) that releases the spring force (06) to allow the skate to retract into Figure 44 position C) for retrieval from the well.

Any qualified slickline tool manufacturer can design and construct such tooling using standard mechanisms and their experience with other tools like the Figure 43 gauge hanger.

Conventional Gauge Hanger Tool

Figure 43 Gauge Hanger (Interwell website)

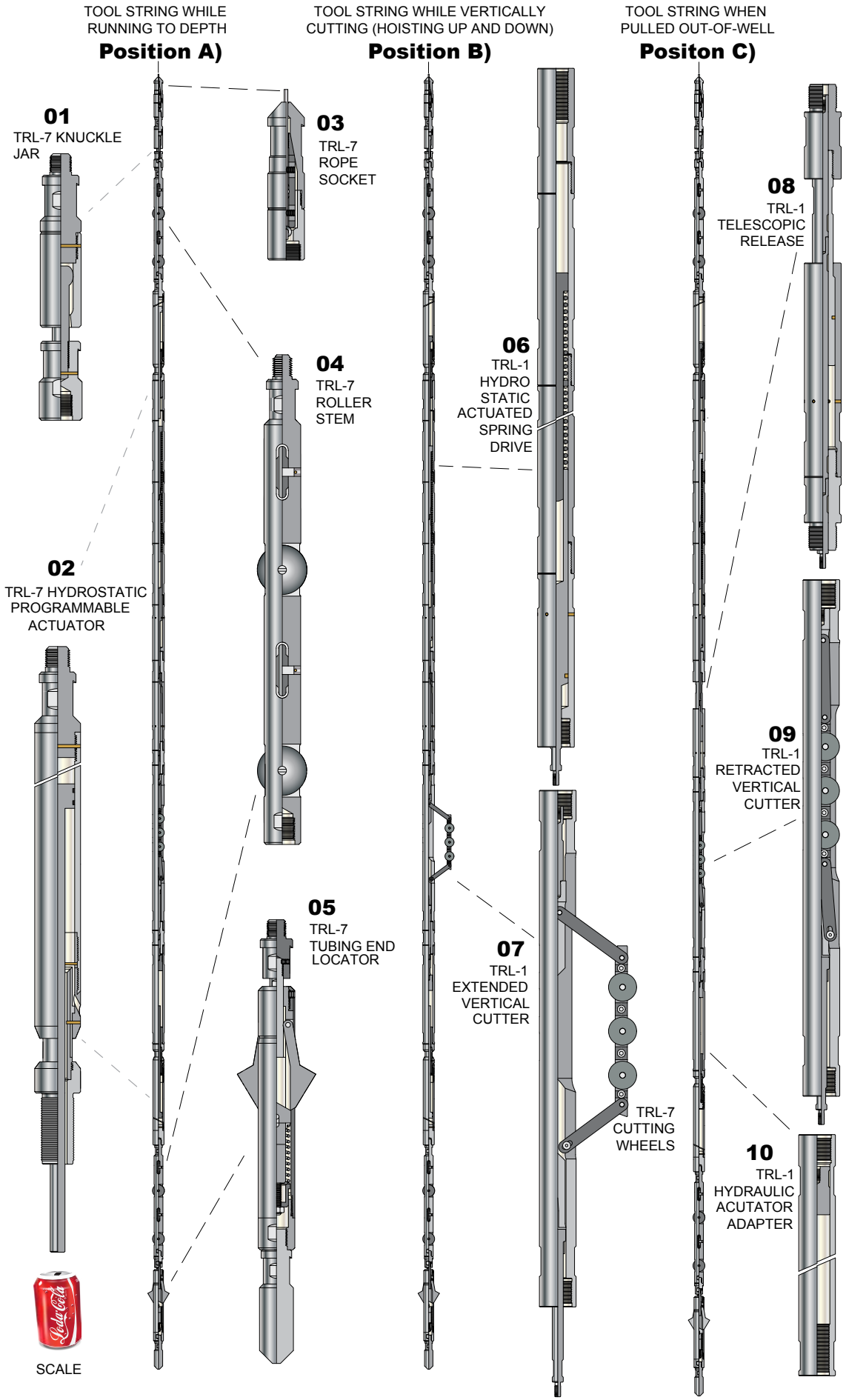


Figure 44 - Vertical Cutter Slickline Tool String in Running A), Cutting B) & Retrieval C) Positions

How does a Packer enter the Casing?

Severing tubing that is in tension allows the severed end to fall and slump which may, or may not, provide sufficient space for inflating a packer within the casing. A wireline impression block and tubing end locator can be run to determine if sufficient slump has occurred.

If the tubing does not slump sufficiently, the packer can be inflated and deployed from inside the tubing as shown in Figure 45.

In such cases, step #3 of Figure 12 is extended to steps #3A and #3B of Figure 45, wherein the packer is partially inflated with tubing pressurization extruding the packer from the end of the tubing to cause the hanging tubing to lift off the piston and/or force the tubing spear downward.

During extrusion or after extrusion from the tubing, the packer will further expand to create a seal and form a piston in the casing.

Inflatable packers are like your car tyre. The pressure in your car tyre can be low and still support your car because the weight of your car compresses the tyre and, thus, increases the pressure in your tyre. Similarly, high inflatable pressure within the tubing may result in a lower inflatable pressure in the casing, but it will still expand to the casing as pressurised fluid above compresses and increases the inflatable element's internal pressure to create sealing side force.

A cross-linked polymer fluid can also be placed above the inflatable to prevent leakages due to changes of diameter when expanding from the tubing to the casing.

Proven cross-linked polymers (Reddy, 2003)[59] are regularly used to stop dire downhole fluid leakages and are very strong semi-fluid gels that are difficult to shear and, thus, can seal across relatively large gaps.

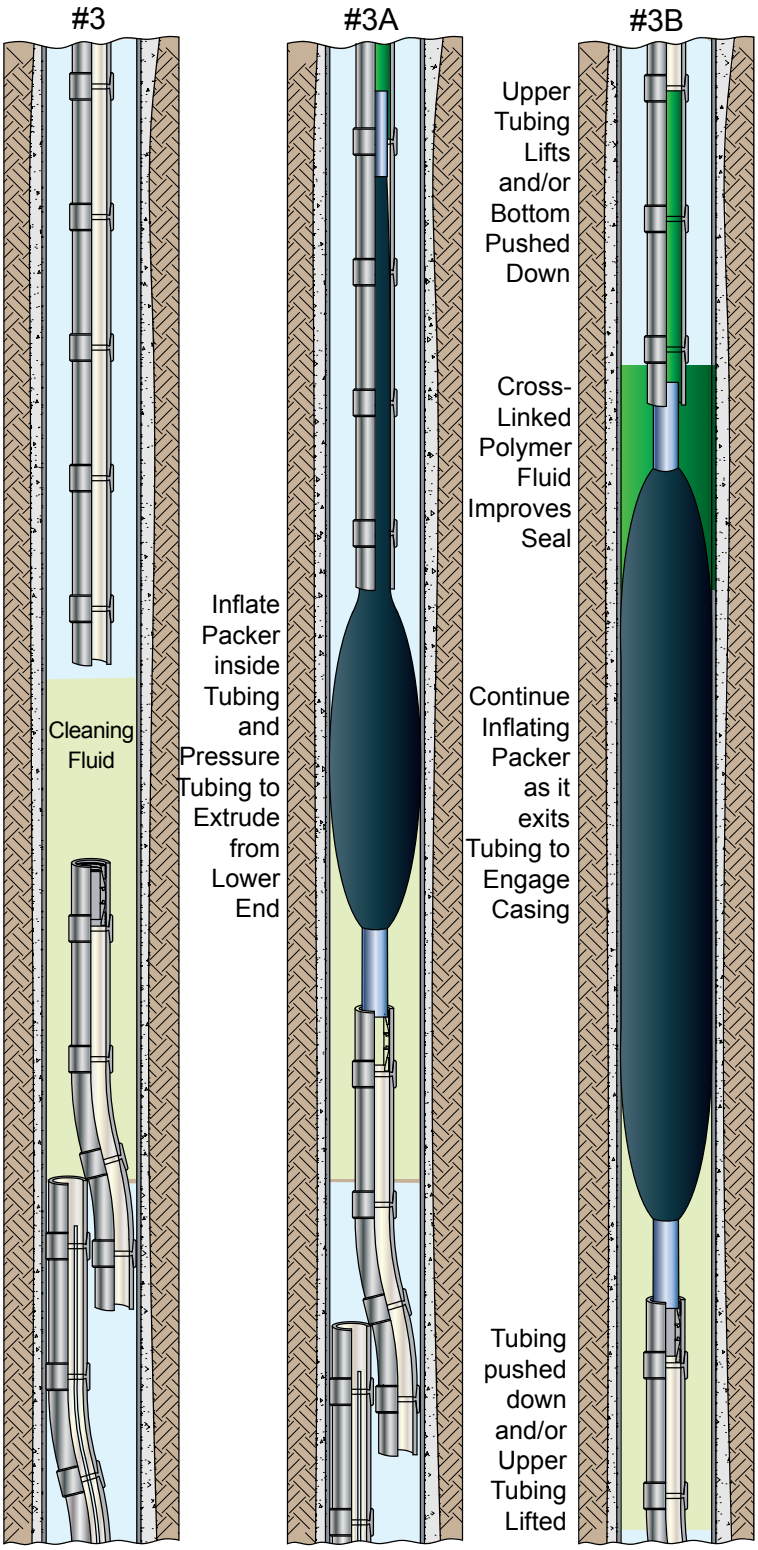


Figure 45- Thru-Tubing Packer Inflation

What about Packer Element Damage?

Conventional inflatable packers use slats attached to a robust elastomeric element, like your car tyre, whereby the slats protect the element and anchor the packer to the casing.

The inflatable manufacturer can attach smooth slats to inflatable elements to minimise friction and allow it to slide while protecting the inflatable elastomeric membrane during tubular compaction.

Alternatively, more rugged and lower cost packers can be designed and qualified. For example, a Kevlar (bullet proof) bag can be filled with a particle sealant like Sandaband® (Sassen, 2011)[114] to be extruded from the tubing, as shown in Figure 46, without damaging the bullet proof bag. Pleats in the Kevlar bag can allow particle sealants to fall while internal bow springs expand the pleated bullet proof bag as it transitions from tubing to casing.

Oilfield Innovations are recommending inflatable packers for compaction to minimise the cost of developing the new

technology, but a low-cost Kevlar bag compaction piston could also be part of the development if there are concerns about damaging inflatable packers.

How do you Clean the Casing?

The piston packer contacts the casing. As it is hydraulically forced downhole, previously placed cleaning fluid and the metal slats attached to the elastomeric inflatable packer element or Kevlar bag can scrape and clean the casing walls to provide a water wettable surface for cement bonding.

Cleaning the casing during compaction also minimises waste fluids by keeping such fluids and debris downhole.

What about Piston or Casing Leakage?

Leakages above or around the compaction piston can be managed by adjusting the pump rate to exceed the leakage rate and/or with industry proven thixotropic fluids, polymers and/or brines or drilling mud with lost circulation material (LCM), as illustrated in Figures 45 and 46.

Many positive displacement surface pumps can supply sufficient pressure and volume to maintain compaction movement at a dynamic frictional value. If pump capacity exceeds that needed to keep the compaction moving, small seepage losses in the system are not necessarily an issue.

Cross-linked polymer fluids usable to plug leakages above or around the compaction piston can be time and temperature dependent as well as environmentally friendly (Reddy, 2003)[59], wherein the high fluid friction of the cross-linked gels can effectively seal leakages during compaction.

Alternatively, LCM laden environmentally friendly brine or drilling mud can be used to both seal fluid loses at or above the compaction piston and supply additional specific gravity compaction force.

What about Hydraulic Piston Lock-up?

Pressure integrity above the piston maximises compaction force on the piston, whereas disposal or leakage below the piston is desirable to ensure that trapped fluid does not impede compaction.

Figure 46 describes various methods that can be used to avoid hydraulically locking the piston by trapping fluids below it. The alternatives include valves and injection into the reservoir or another formation.

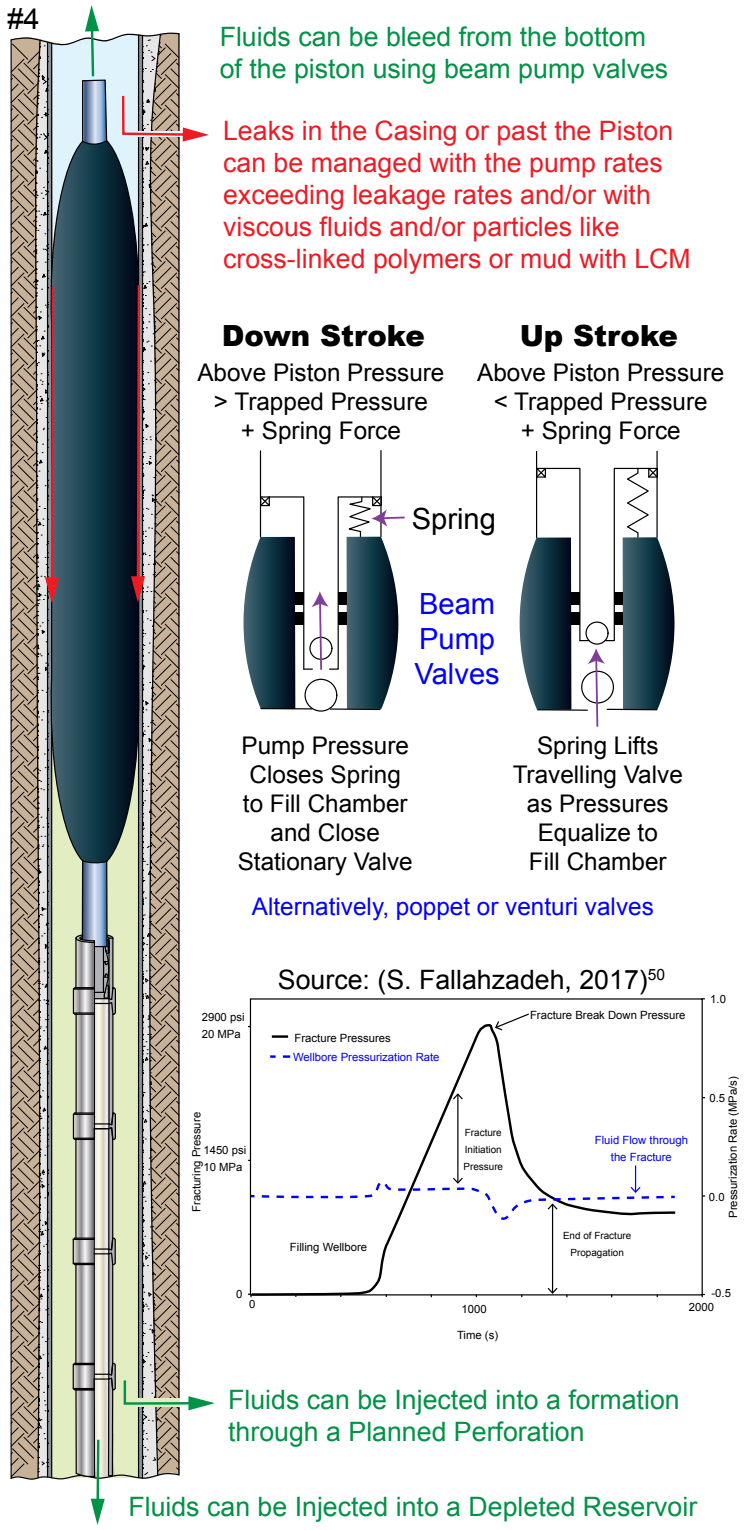


Figure 46- Managing Compaction Hydraulics

Low fluid friction injection into a depleted reservoir is relatively easy.

Perforating and fracturing a non-reservoir formation below the intended compaction depth can also be used to prevent trapping of fluids below the piston.

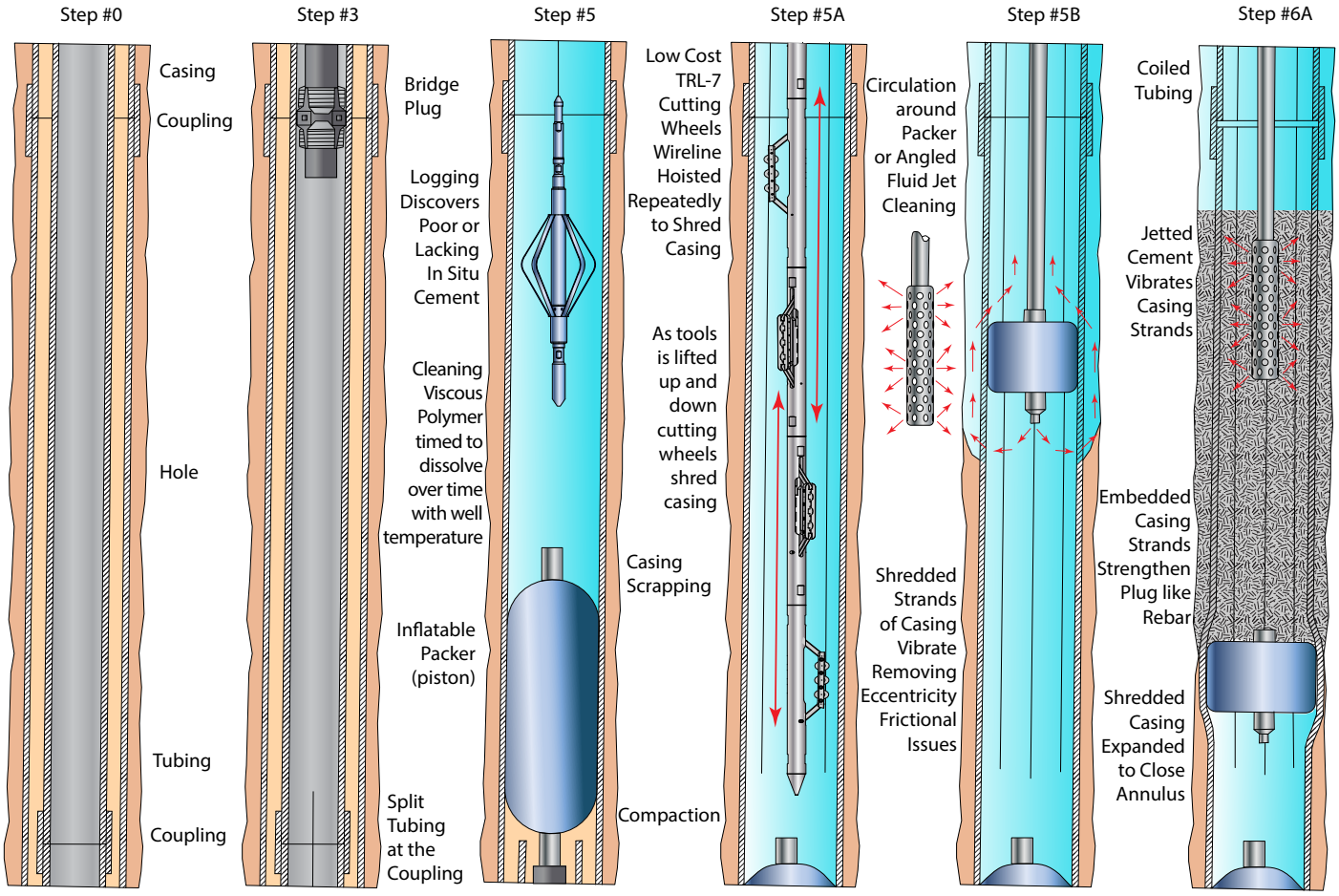


Figure 47- Elevation View: Shred, Wash and Cement (SWC) Method of P&A Annular Cementing

Higher pressure fracture breakdown can be initiated before placing the piston. As shown in Figure 46, fracture reopening back pressure of about 1200-psi, or 8-MPa (Chan[110], 2015; Fallahzadeh[50], 2017) will resist compaction. Heavier fluids can be used to negate or partially offset back pressure due to injection.

Alternatively, or in addition, trapped fluid and/or pressures below the injection pressure can be bleed-off through various valve arrangements through the centre of the piston comprising, for example, an orifice, a venturi, poppet valve or a combination of traveling and stationary valves like that depicted in Figure 46.

What about repairs requiring Casing Milling?

For various reasons squeeze cementing repairs can be necessary, even for a drilling rig, when milling is undesirable and/or when cutting and pulling partially cemented casing is practically impossible. Various rig and rigless cement squeeze repair methods are usable to repair in-situ cementation (Zwanenburg[94], 2012, Teleghani[58], 2016; Tanoto[109], 2017).

When conventional squeeze cementing is insufficient and the casing cannot be cut and pulled, the remaining rig-based option is milling the casing to remove the poor cement and reach a virgin rock face.

Casing section milling is time consuming and exposes a rig's blowout preventers to damaging metal fragments called swarf and, hence, casing section milling is avoided where possible even during drilling rig P&A. Accordingly, rig-based P&A proponents have developed improved methods of squeezing cement like Perforate, Wash and Cement (PWC) which is commonly referred to as Perf & Wash. A Perf & Wash method can avoid milling by perforating the casing, washing the annulus through the perforations and placing cement across the whole cross section of the wellbore (Delabroy[27], 2017).

Perf & Wash can be used to remove the need for traditional rig-based casing milling (Ferg[32], 2011; Denmon[33], 2016; Delabroy[27], 2017); however, Perf & Wash simply adds more perforations to conventional squeeze cementing practice to provide better circulation and, therefore, can also be used riglessly with coiled tubing (Moeinikia[63], 2014; Skorpa[115], 2016) to deliver a rigless work scope where multiple tubulars are embedded in cement.

Cleaning circulation through small perforations can require high flow rates and create large volumes of waste that may, in various instances, be unsuitable for rigless pumping and waste storage capacities.

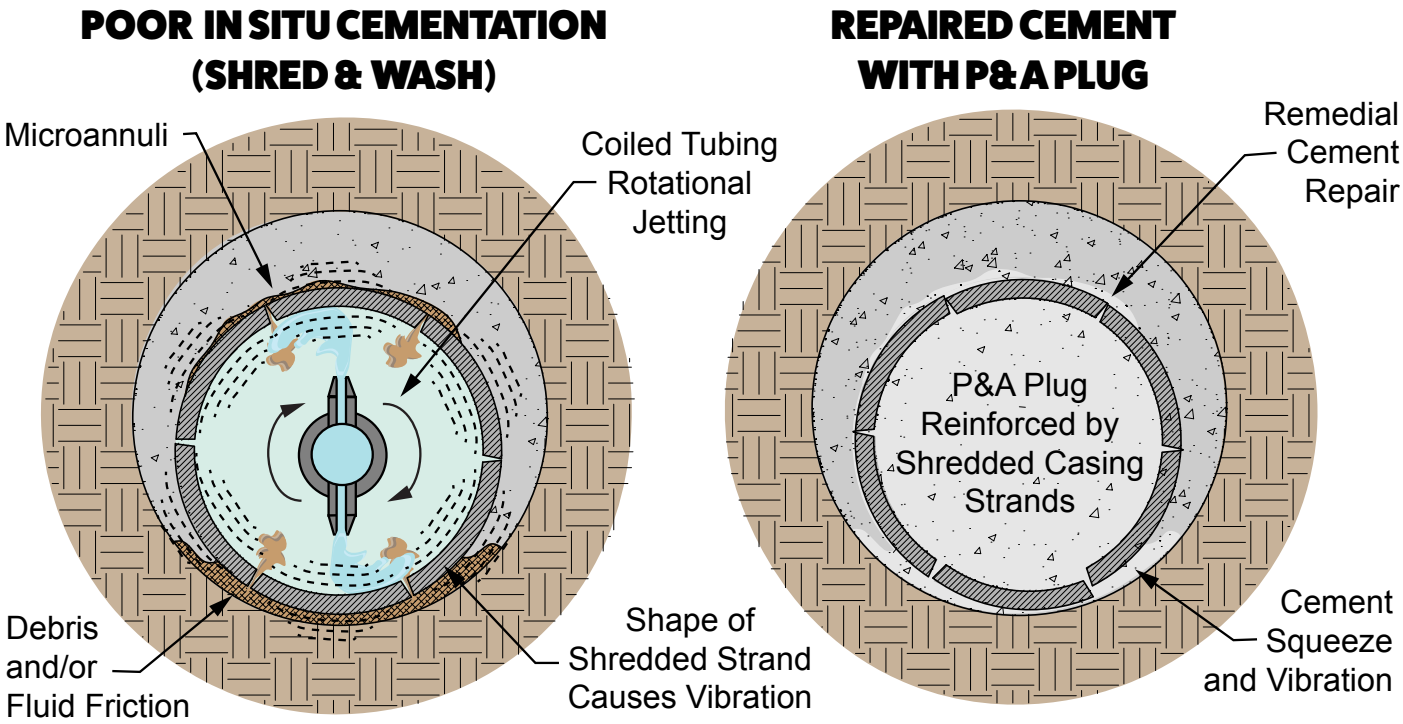


Figure 48 - Plan View: Shred, Wash and Cement (SWC) Method of P&A Annular Cementing

Accordingly, Oilfield Innovations have patented a Shred & Wash method shown in Figure 47 that is better suited to rigless operations.

Rig-based proponents of Perf & Wash have performed full-scale experimental testing to demonstrate that good cement placement is possible when the tubulars are left within other tubulars in the hole, even when control lines are present. The experiments showed that cement can be well-placed within the in-situ tubing annulus, but some microannuli may be present, albeit they are probably not continuous (Aas, 2016)[25].

Perf & Wash can be improved by shredding the tubular wall to eliminate cleaning and cementing through numerous small diameter perforations, wherein shredding also removes microannuli through vibration as depicted in Figures 47 and 48.

Figure 47 step #0 shows production tubing within uncemented casing. Step #3 of Figure 47 replaces step #3 of Figure 12 and depicts vertically slicing across a coupling to eliminate the need for severance.

Within step #5 of Figures 12 and 47, logging discovers that the in-situ cement is poor or lacking. Figure 47 step #5A then shreds the casing using tools similar in configuration to the right side of Figure 14.

Figure 47 step #5B illustrates washing and cleaning the shredded casing with a fluid inflatable packer element used to divert circulation through the shredded casing strand gaps.

Figure 47 step 6A uses coiled tubing cementing and replaces step #6 of Figure 12, wherein the fluid inflatable packer of step #5B was further inflated to expand the shredded strands of casing and provide annulus support for the P&A plug.

Oilfield Innovations' TRL-0 Shred & Wash method of Figures 47 and 48 can be proved and qualified with coiled tubing flow rates to reduce the need for rig-based P&A.

Shred & Wash can reduce required pump flow rates and waste generation through the vibration of shredded casing strands, which will also reinforce the P&A plug like rebar reinforces concrete.

As shown in Figure 47 and Figure 48, shredded casing strands can vibrate when fluid is jetted against their inner arc, wherein fluid diversion acts toward one side of the strands' inner arc to induce twisting forces that can vibrate the strand to dislodge debris and embed the strand within cement.

Research that justifies numerous small perforation holes in casing equally indicates that the larger vertical cuts of Shred & Wash could provide a viable alternative to casing section milling for both platform and subsea wells.

Shred & Wash is an upside potential for the present tubing compaction support request or, alternatively, can be a part of a separate support request for rig-based and rigless P&A.

What about Cutting & Pulling Casing?

After pulling the tubing, in cases of uncemented casing-in-casing, a rig-based P&A typically cuts and pulls casing to provide the work scope shown on the left of Figures 5 and 49.

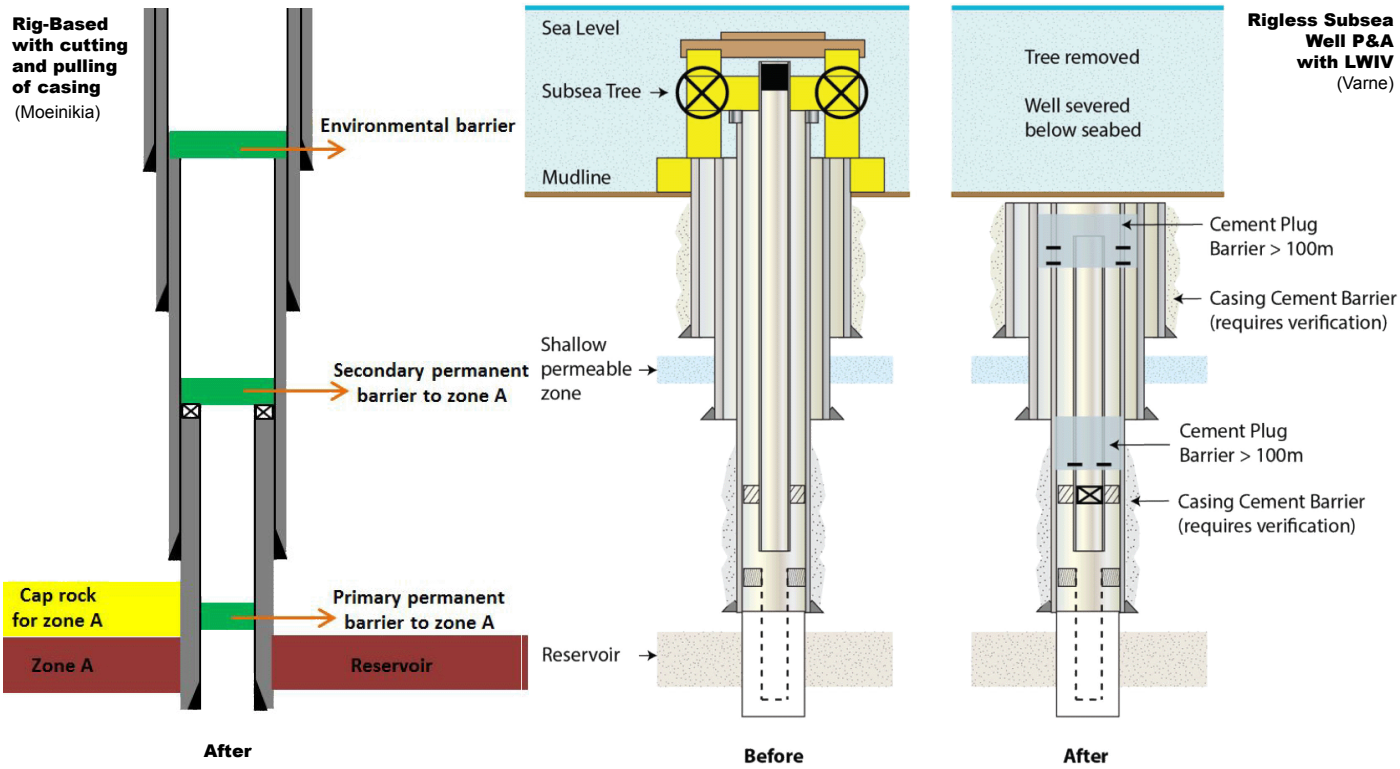


Figure 49 - Simple schematic of abandoned wells (left: Moeinikia[63], 2014; right: Varne[85], 2017)

Figure 49 shows an elevation view for a rig-based P&A work scope on the left and an elevation view of a rigless P&A work scope for a subsea well on the right.

A rigless pulling and jacking units (PJU), pictured in Figures 24 and 25, can also cut and pull casing (Canny, 2017)[17], just like a rig, only much slower.

Uncemented casing-in-casing arrangements are, by design, typically located significantly above producible hydrocarbon zones, but there may be overpressure water bearing zones or unproducible hydrocarbon layers around which P&A plugs should be located.

As earlier discussed, the legal liabilities of hydrocarbons and pressurized water zones are not the same. Probabilistic risk-based P&A approaches, proposed by Aas[25], DNVGL and others, can be more acceptable for over-pressure water zones and insignificant unproducible hydrocarbon zones.

Also, work by various authors (Davies[60], 2004; Marriott[62], 2007; Gubanov[61], 2014) shows that other methods like reverse cementing can also be used to improve the cementing of annuli of casing-in-casing arrangements to mitigate the need to cut and pull casing.

From a practical viewpoint, with respect to the right side of Figures 49 and 50, using a risk-based approach to justify not cutting and pulling casing to isolate a water bearing zone or unproducible hydrocarbon zones may provide acceptable legal liabilities because consequences are virtually non-existent. Water leakages into offshore strata and/or the ocean cannot be measured and unproducible hydrocarbon layers have insufficient permeability to leak in any meaningful amounts.

For non-reservoir P&A plugs #3 and #4, a Rigless Pulling and Jacking Unit (PJU) can cut and pull casing or, given the extremely low to negligible risks of leakages from water zones or hydrocarbons trapped in impermeable rock, a risk assessment can be carried out for use of rigless Perf & Wash, Shred & Wash and/or Reverse Cementing methods that can be used to keep risks as-low-as-reasonably-practicable (ALARP), from a legal liability viewpoint, to provide the rigless work scope on the right side of Figure 50.

Compare your P&A Method to Rig P&A!

Figure 50 elevational cross-sectional schematic details the differences between rig and our rigless P&A for comparison with Figure 49 rig (Moeinikia, 2014)[63] and conventional rigless P&A (Varne[85], 2017)[85].

During Phase 1 P&A, both rig and rigless work scopes use low cost wireline spooling equipment with a single strand of wire (slickline) or a braided wire cable, wherein either can be electrified (electric-line).

Wireline equipment is predominantly used in Phase 1 reservoir P&A. Some companies use wireline to set mechanical plugs to facilitate pulling the tubing with a rig (Shell[6], 2017) while others use wireline crews to set multiple P&A cement plugs to isolate the reservoir (Plumb[16], 2003).

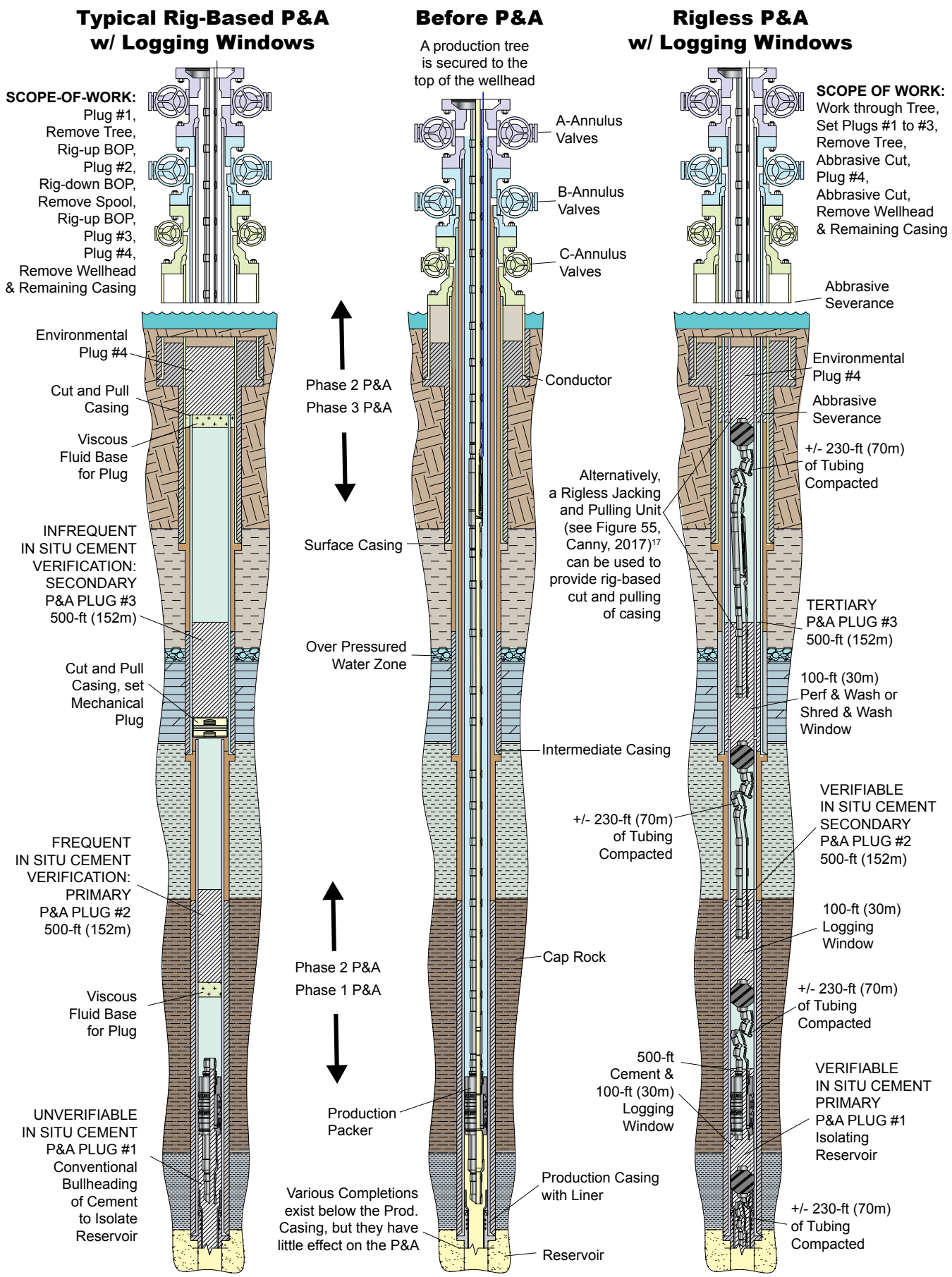


Figure 50 - Comparison of Rig-based to Rigless P&A with Logging Windows

For challenging rig and rigless P&A work scopes, coiled tubing can be used to perform reservoir and intermediate P&A in Phases 1 and 2 (Freeman[12], 2015).

As shown in Figure 50, when isolating the reservoir in Phase 1, rig-based P&A normally leaves the production packer in place. Conventional rig and rigless P&A typically bullhead cement into the reservoir through in situ tubing (Olsen, 2017)[105], whereas our compaction method can compact tubing below the production packer to verify in situ cement and place a primary P&A plug.

Once the well can be opened to atmosphere, rigs remove the tubing and associated production jewelery before logging in situ cement and placing a viscous fluid to support a primary P&A plug #2 as shown on the left of Figure 50. A rig will then cut and pull uncemented production casing before setting a mechanical plug to support a secondary P&A plug #3. For reasons of cost, rigs infrequently log in-situ cement for a secondary P&A plug. The intermediate casing will then be cut and pulled before setting an environmental plug and removing above seabed well equipment.

Alternatively, instead of cutting and pulling casing, a rig may use a Perf & Wash method (Ferg[32], 2011; Abshire[69], 2012; Khalifeh68, 2013; Moeinikia[63], 2014; Aas[25], 2016; Delabroy[27], 2017) and, therefore, the method is equally applicable to lower cost rigless P&A.

Oilfield Innovations' rigless method uses a piston to compact part of the tubing, and any associated jewelery, control or injection lines, to create at least a 100-ft (30m) logging windows before placing the 500-ft (152m) cement plugs through the remaining in situ tubing as depicted on the right of Figure 50.

Oilfield Innovations can use Perf & Wash, Shred & Wash and/or various techniques including Reverse Cementing methods (Davies[60], 2004; Marriott[62], 2007; Gubanov[61], 2014; Vrålstad[106],2016; Durmaz[107], 2016; Rogers[108], 2016; Tanoto[109], 2017; Olsen[105], 2017) for placement of P&A plugs #3 and #4 on the right of Figure 50.

Alternatively, rigless pulling and jacking units can cut and pull casing (Canny, 2017)[17] to make the upper portion of the well P&A look like that of a rig-based P&A where necessary.

After rigless P&A plugging, the platform or subsea equipment above the mudline is hydrocarbon free and various rigless methods using abrasive cutting, explosives or other means are used to remove the above seabed equipment with jacks and cranes.

Accordingly, as shown in Figure 50, using various industry proven methods and equipment, Oilfield Innovations' rigless method can deliver a rig-equivalent P&A using rigless logistical means that can be combined with other decommissioning activities to reduce total P&A cost by 30% (Siems, 2016)[21] to 60% (Varne, 2017)[85].

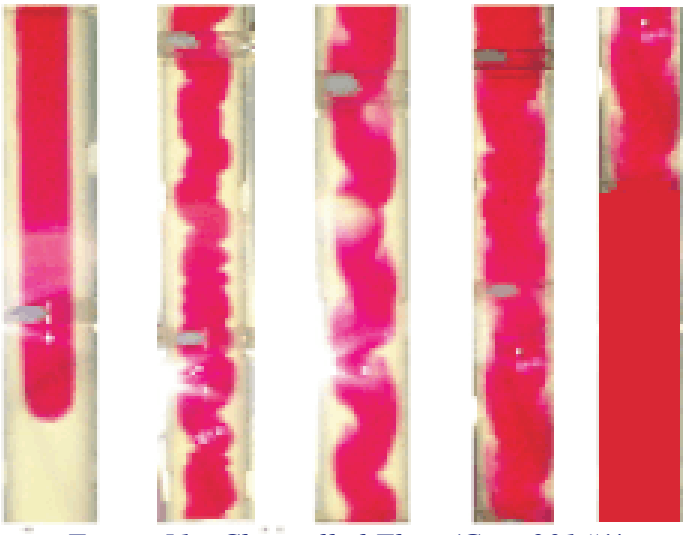


Figure 51 - Channelled Flow (Guo, 2014)[64]

What about 500 Foot P&A Plugs?

Both rig and rigless methods can place 500 feet (152 m) of cement and both require 100 feet (30 m) of confirmed in-situ cement bonding. Therefore, regardless of the cement plug height, a 100-foot (30 m) logging window is sufficient.

During rigless operations the end of the severed tubing hanging from the wellhead can be centralised above the 100-foot (30 m) window to better place a 500-foot P&A plug, wherein 400 feet of tubing would be embedded within the plug.

Cement within the 100-ft (30m) logging windows provides adequate compliance, but experiments (Aas, 2016)[25] demonstrate that embedded tubing can provide sealing P&A plugs and placing 500-ft (152m) P&A plugs would be acceptable. Also, unlike the small diameter stingers used by drilling rigs, the constant diameter of the tubing can provide an uncontaminated balanced plug (Rove, 2014)[29] making less than a 500-ft (152m) cement plug appropriate when using computer modelling to adjust pumping parameters (Guo, 2014)[64] for channelling of heavy cement through lighter fluids, as shown in Figure 51, within the lower 100 feet (30m) window.

Accordingly, Oilfield Innovations' rigless method can provide 500-foot cement plugs without unnecessary extra cutting and compacting by embedding in situ tubing above the logging window and using it to place a balanced cement plug consistent with industry practice.

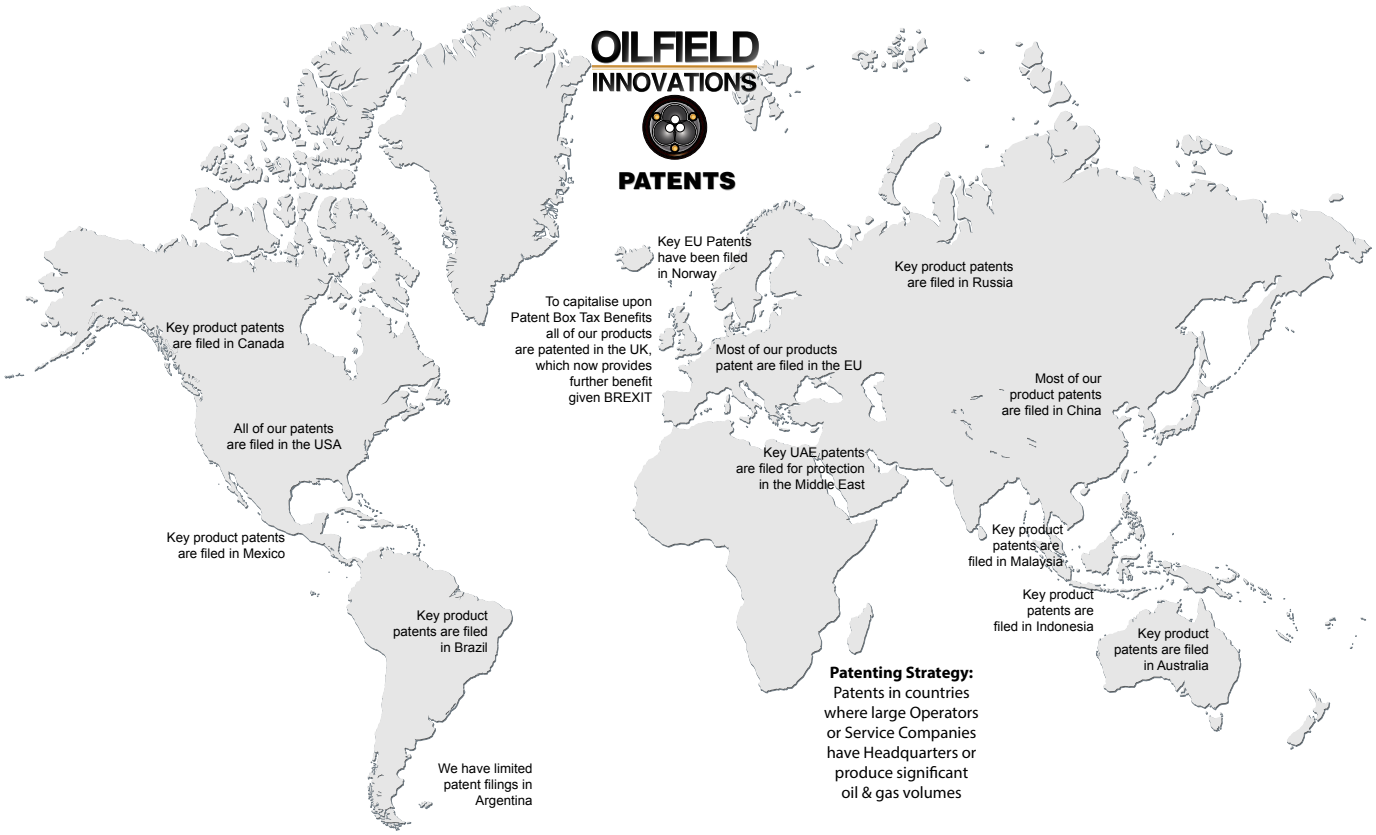


Figure 52 - Oilfield Innovations Worldwide Patents

Upside Potential for your Method?

Oilfield Innovations have a portfolio of patents relating to rigless P&A methods within the countries shown in Figure 52. This has taken many years and fully depleted our funding capacity.

We are willing to combine our P&A patents into a portfolio that can be marketed to pay for development of the various new technologies within the patents.

It is not the purpose of this document to demonstrate the viability of our additional patented technologies so we briefly explain the core principles on the following pages to allow the reader to see the upside potential that our patented methods can provide in the future. For those who are interested, Oilfield Innovations can provide more information.

How protected are your Patents?

We have ring fenced patents with other patents that provide a worldwide legal monopoly for the methods and equipment described herein. Breaking our ring-fence of patents would be extremely difficult regardless of available legal resources as inventions are not only broadly claimed but also intertwined and cross referenced.

For example, the patent described by Figure 53 describes the use of well abandonment to develop new technologies and further references the methods described herein.

Also, Figure 54 describes method and apparatus for using abrasive filament cutters that claim vertical cutting and cross cutting of vertically cut surfaces, which also references fluid motors run on wireline in Figure 55 that are claimed as part of our primary compaction method.

Finally, Figures 56 and 57 cement bond logging before and after P&A cement placement also references our patented method of tubular compaction.

The value of our patents is not just their simplicity and ability to provide step changes in the P&A costs, their value also relates to worldwide legal protection for enterprises that develop and distribute licenses for using the method in other countries.

If the patents are controlled by those wishing to profit from or drastically reduce the cost of P&A, the method can be licensed to local companies in other countries wishing to use the method.

If worldwide patents are controlled from an oil and gas technology centre or city, the beneficial effects of being a worldwide centre of excellence and leader in low cost P&A can further help the centre or city.

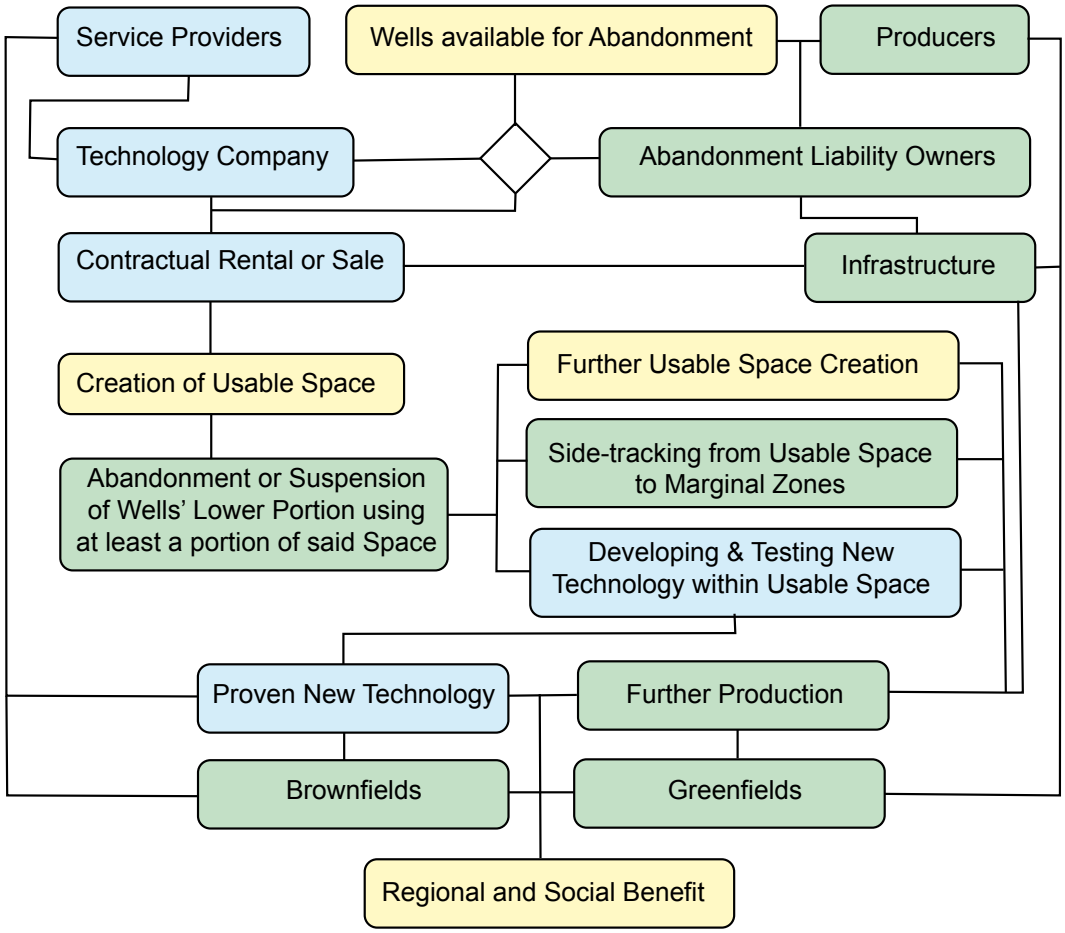


Figure 53- UK or Scottish University Research Funding Patent

How can your other Patents Help?

Oilfield Innovations have found that "*Catch-22*"[97] for companies who want to develop new technology consists of members of the "group" of Oil and Gas Producers that will not use new technology until it has already been used by another member of said "group" … which effectively prevents the development of new technology.

Oilfield Innovations has patented the Figure 53 market of testing new technology in the relatively risk-free environment of a well where the reservoir has been isolated using the low-cost method of P&A described herein, whereby the lower end P&A plugged well could be used to perform new technology development for the oil and gas industry.

The decommissioning process takes many years to complete and wells may be abandoned years in advance of facilities cessation of production. Combining low cost rigless P&A with the logistics of other decommissioning activities can also extend the P&A period.

Once the reservoir is isolated and before surface environmental plugs are placed, a partially abandoned well could be used as a "test well" for new technology.

Oilfield Innovations have patented marketing such wells as test wells that can be used for research and development.

Oilfield Innovations can assign our patented market for renting a partially abandoned well for use as a test well to, for example, Universities who could perform research for service companies developing new technology like the cutting and logging technologies described in the following pages.

Producers own the abandonment liability and the well so they can do as they wish within regulatory requirements; however, Producers wanting to use our low-cost method of P&A could be further encouraged to, in their own self-interests, allow Universities to work with Service Providers who wish to rent their partially abandoned wells for testing of new technology.

Like OGIC and OGTC matching funding, the rental of the partially abandoned well could be paid to the University to fund research that may, or may not, demonstrate that the technology is viable based upon the data collected.

In either case, Producers benefit and the Service Providers can break through the "*Catch 22*"[97] new technology barrier.

What is an Abrasive Filament Cutter?

Oilfield Innovations have patented the Figure 54 concept of using a super abrasive or diamond wire filament cutter configured like a conventional horticultural strimmer or weed-wacker.

Super abrasive or diamond wire filaments are proven oil and gas cutting technology used in, for example, conductor cutting, wherein adapting the proven filament technology to be deployed by a strimmer or weed-wacker arranged for downhole severance could be used to cut through multiple conduits and cables where conventional knife, chemical and explosive cutters cannot.

Some off-the-shelf knife blade cutters can sever tubing and adjacent control lines while others cannot.

Cutting a single tubular with knives, chemicals and wheels is relatively common in the oil and gas industry but cutting through more than one concentric tubular is very challenging and generally involves abrasive fluid blasting, large explosives or casing milling to provide access for further cutter deployment.

Abrasive particles can be jetted with fluid to cut through multiple conduits and casing but such tooling is not necessarily suited for thru-tubing severance of multiple tubulars and is primarily used in larger diameter casing.

Thru-tubing automatically spooled super abrasive or diamond wire filaments rotated by a fluid or electric motor could abrade through multiple concentric tubulars and control lines.

Rotated diamond wire filament cutting is not only applicable to P&A. It is also applicable to stuck pipe situation where, for example, drilling or milling strings have become stuck during drilling or workover operations and a means of through tubular severance is needed.

A downhole filament cutter could be run on drill pipe, coiled tubing or electric-line with pipe rotation, fluid motor or electric motor rotation.

Within rigless P&A, where in situ cement is poor or lacking, the casing could first be vertically shredded and then an abrasive filament cutter could be used to cross cut the vertically cut wall strands to create confetti like debris that would fall downward, wherein abrasive filament cutting could be used to riglessly remove wall sections to accomplish the same scope of work as casing milling.

How does a Wireline Fluid Motor Help?

Another upside potential innovation is coiled tubing fluid motors run on wireline as shown in Figure 55. Combining non-rotational mechanisms and a seal at the top of a coiled

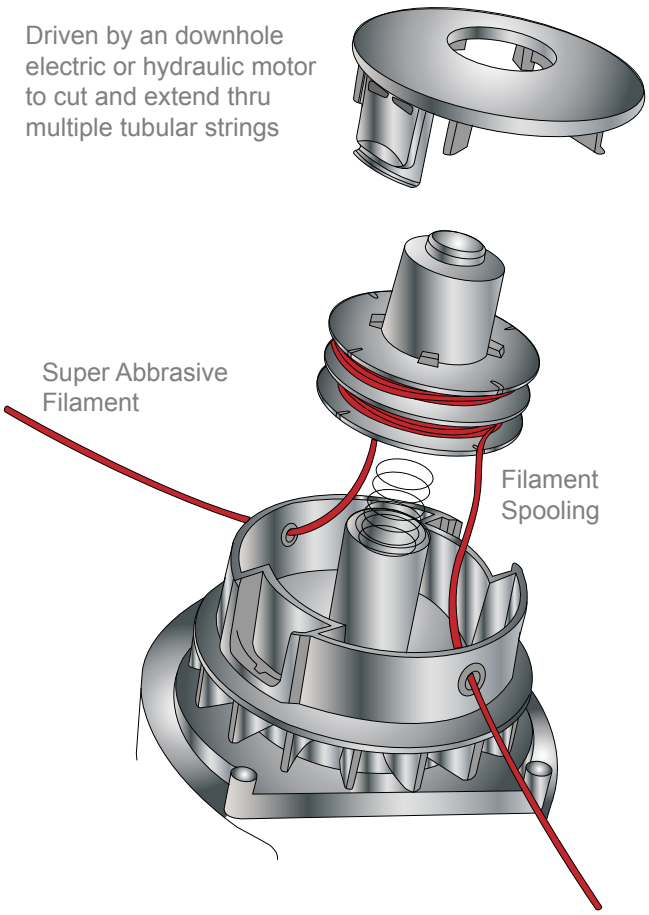


Figure 54- Abrasive Strand Tubing/Casing Cutter

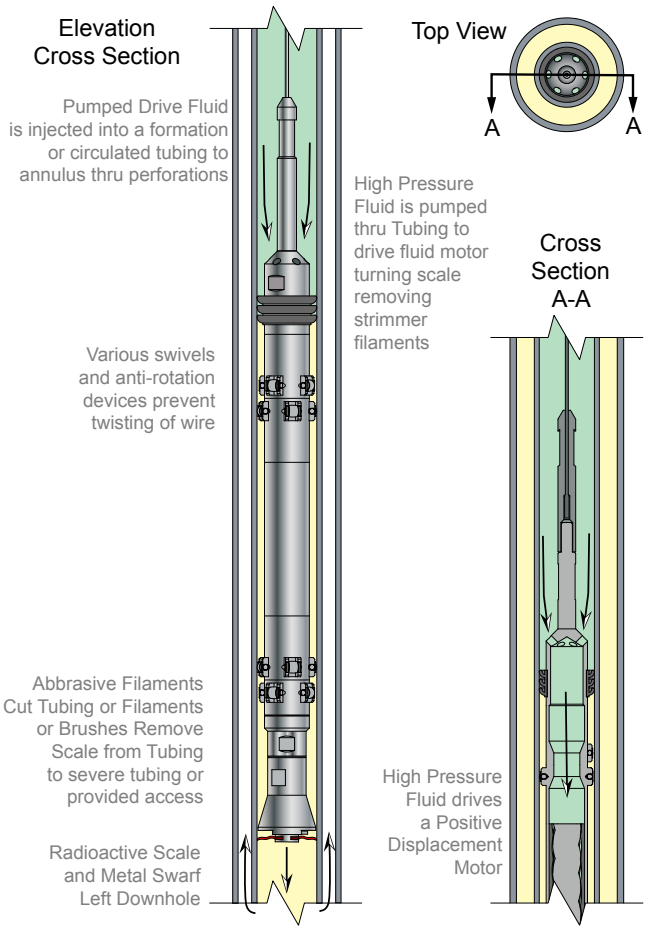


Figure 55 Wireline Fluid Motor Cleaning or Cut

tubing motor can allow it to be run on wireline, whereby fluid may be pumped down the tubing when lowering a fluid motor on wireline to, for example, clean LSA scale or mill obstructions from the tubing and/or sever tubulars when a abrasive filament cutter is held at a specific depth.

A primary advantage of using a fluid motor run on wire during P&A is that the pump used for cementing can also be used to run a fluid motor operated brush or filament cutter to, thus, minimise the volume of equipment and utilities needed for rigless P&A.

Through tubing operations can be obstructed by LSA scale that can be brushed or cut from the tubing wall and left downhole below a wireline run fluid motor operated by either injection or circulation.

Proven coiled tubing fluid motors, usable on wireline, are available in sizes ranging from 1.68 inches (42.6 mm) to 5 inches (127 mm) in diameter which could be used in 2 $^{3}/_{8}$ inch (60 mm) to 7-inch (178 mm) production tubing.

Patents for Thru-Tubing Logging?

Current logging technology is not able to log through multiple casings (Moeinikia, 2014)[63] and the legal liability of potential P&A leakages drives a need to measure the quality of in-situ cementation.

Vibration of unsecured tubing within casing prevents conventional cement bond logging tools from accurately sending and receiving acoustic pulses.

Securing the tubing by spiking it to the casing prevents such vibration and connects transmitters and receivers of acoustic logging signals with the casing to measure bonding of in situ cementation.

Significant upside potential exists for a method of logging through tubing and/or multiple casings before setting a P&A plug is exemplified by industry's desire to leave the tubing in place, whereby if the results of logging through tubing showed poor or lacking cement the tooling could be pulled and a rigless repair carried out.

The left of Figure 56 shows the well bore before P&A begins, while the right side shows the installation of an array of logging tools using driven spikes to secure the tubing and engage the transmitters and receivers to the casing wall.

Driving spikes through the tubing using, for example, the Figure 38 Gator Perforator can mechanically secure the tubing and connect a logging tool to the casing to send and/or receive acoustic pulses and measure the casing's bond to in-situ cement.

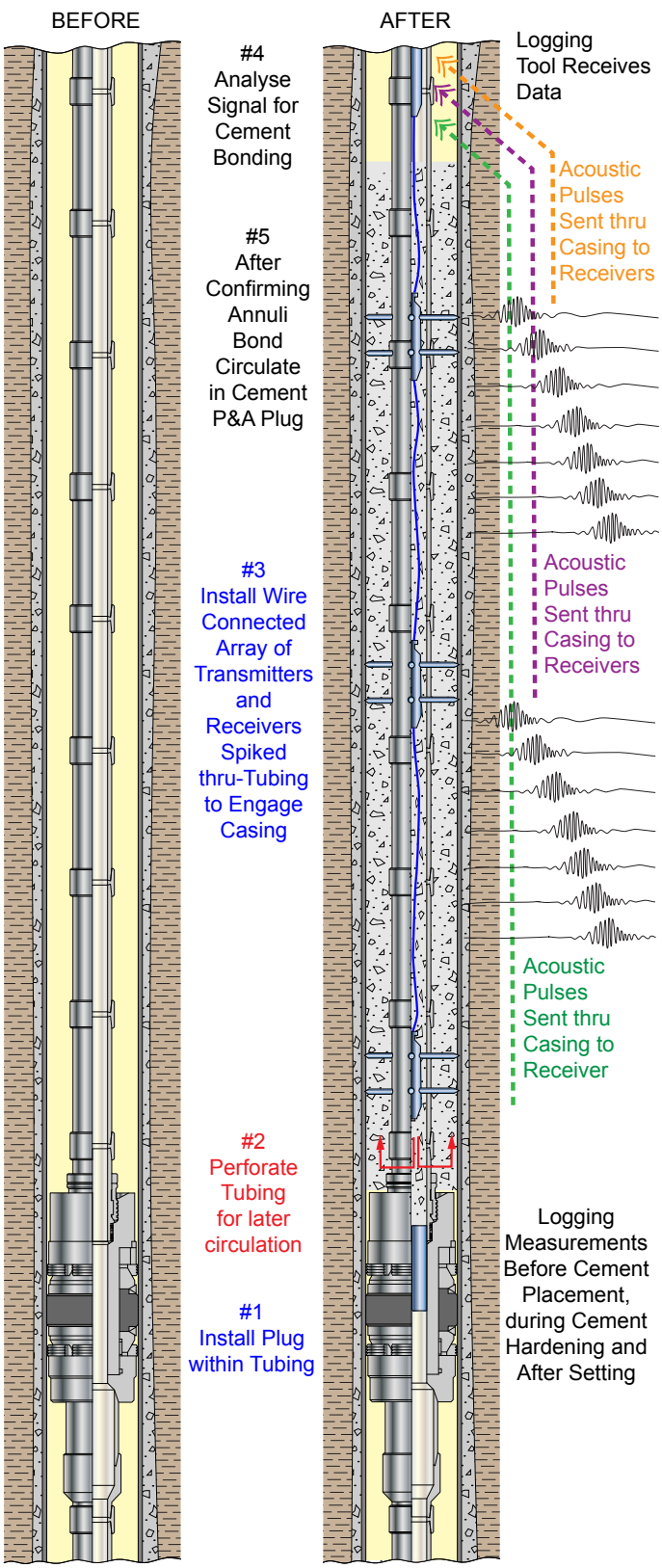


Figure 56 - Through Tubing Cement Bond Logging Rig-Equivalent Works-cope P&A Plugging

An array of transmitters and receivers can be connected by and run on wire that can be used to transmit data and initiate, for example, an explosive charge that drives mechanical spikes through the tubing into the casing.

An array of sending and/or receiving tools connected to the spikes sends waves of acoustic signals, or wave-trains (Smolen, 1996)[132], through the tubing to vibrate the casing. Like conventional bond logging, attenuation of the acoustic pulse indicates that surrounding cementation and strata are bonded to the casing as shown in Figure 58.

Spacing of the logging tool spikes and configuring the array to send and receive acoustic wave-trains can be used to provide the coverage of conventional logging tools, which require movement.

Data transmission signals can be transmitted to surface through wire, memory gauges, fluids within the well or the tubing or casing walls extending to surface, after which the received data can be deciphered to measure the quality of in-situ cement over a 100-ft (30m) tubular section.

After analysing the data and confirming the bonding of cement to the casing, a cement plug could be circulated into the well using the in-situ tubing or, alternatively, the inner logging tools could be pulled, leaving the spikes, and Perf & Wash could be used for repair. Alternatively, after pulling the array of tools, a shallower compaction window could be created for Shred & Wash repair, a rigless pulling and jacking unit could pull the tubing for conventional repair or casing milling with a drilling rig could be planned.

Logging after Placing a P&A Plug?

The method can be used for logging after placing P&A cement plugs, as shown in Figure 57, by measuring bond quality and sending a data transmission signal through the wall of the casing to surface or a cable connecting the cement embedded logging tool array to a retrievable memory gauge above the cement plug or to a transponder that sends data transmission signals through well fluids above the plug.

The method of confirming bonding after placing a P&A plug can be accompanied by calibrating in situ cement bonding measurements before placing the plug by either logging through a compaction window or through-tubing, as shown in Figure 56, with further measurements by an embedded array of logging tools after cement is placed to confirm the P&A plug itself.

Placing loggings tools in a compaction window using an array of transmitters and receivers that can be engaged to the casing with spikes or gauge hangers to transmit and receive wave-train acoustic pulses through casing (see Figure 58) can measure bond quality after placing the P&A plug and send data transmission signals after cement has hardened.

Cement bond logging after placing a P&A plug can also be used after cement repairs like Perf & Wash, Shred & Wash or more conventional perforating and squeezing of cement

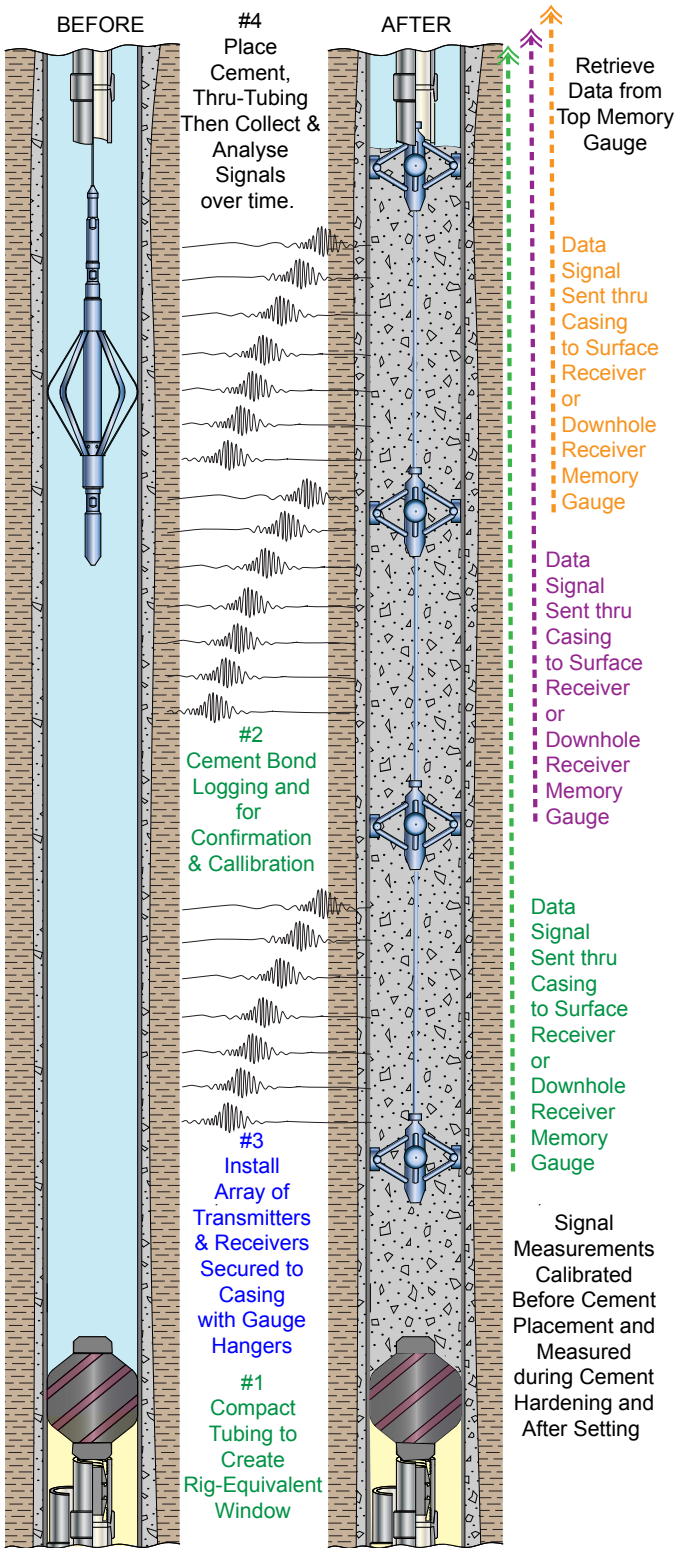


Figure 57 - Cement Bond Logging after Rig-Equivalent Work-scope P&A Plugging

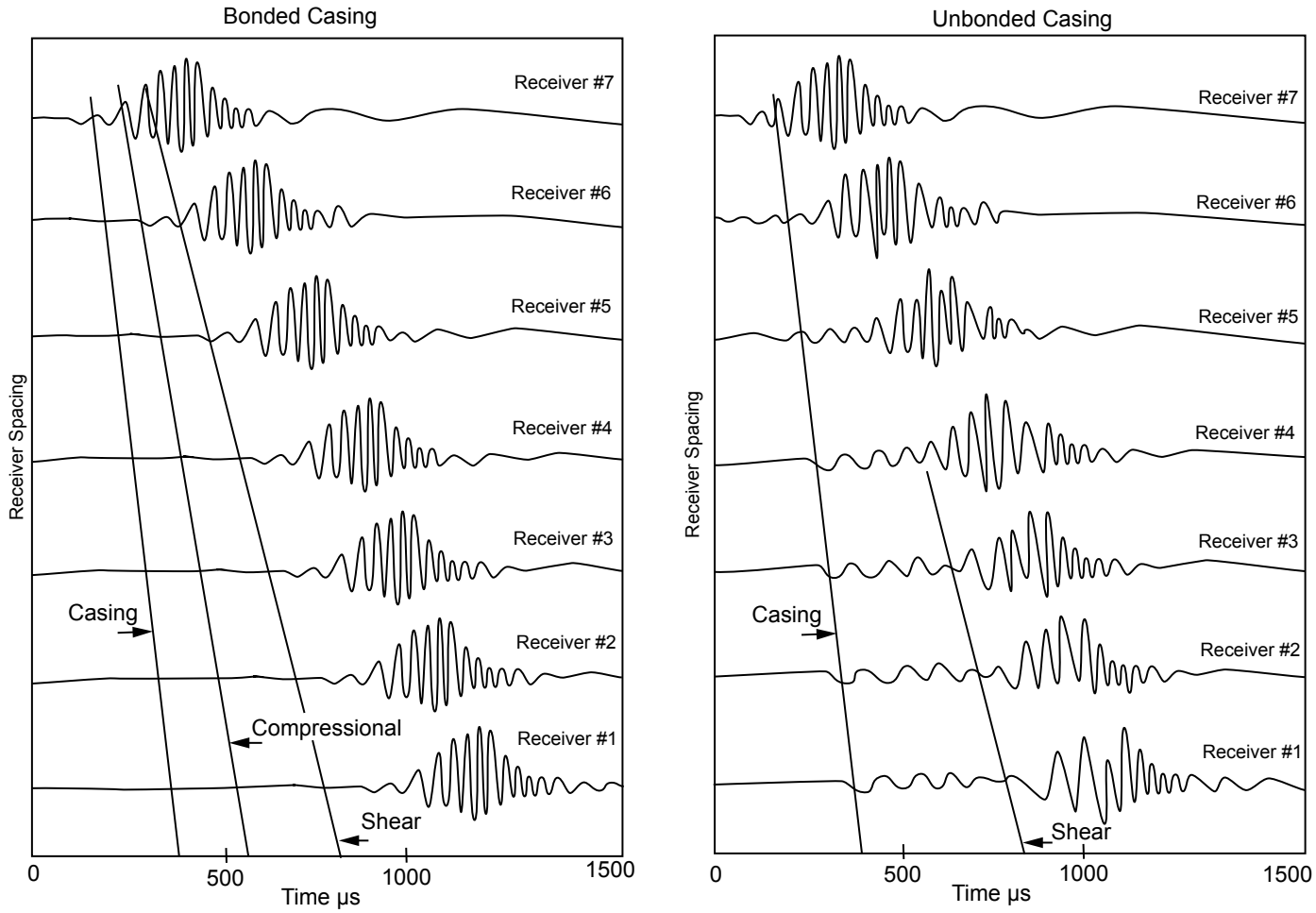


Figure 58- Wavetrain recorded at each receiver with an array type tool (Smolen, 1996)[132]

into annuli behind the casing to confirm that a repair was successful.

Accordingly, the legal liability for any future leakages from well abandonment can be avoided by measuring and proving that a good P&A plug was placed and subsequent leakages could only have been caused by natural forces.

Proving that an Operator fulfilled its legal "as-low-as-reasonably-practicable" requirement is important in subsea environments where future leakages can be visible as bubbles or slicks on the ocean surface and, also, in onshore fracked well P&A where proving that the well is not leaking into drinking water formations may be of critical importance.

The above described new technologies could be developed in conjunction with a University using the patented process described in Figure 53 for using well P&A for new technology development.

Oilfield Innovations can provide additional information on the possible development paths for our P&A technologies should the reader be interested.

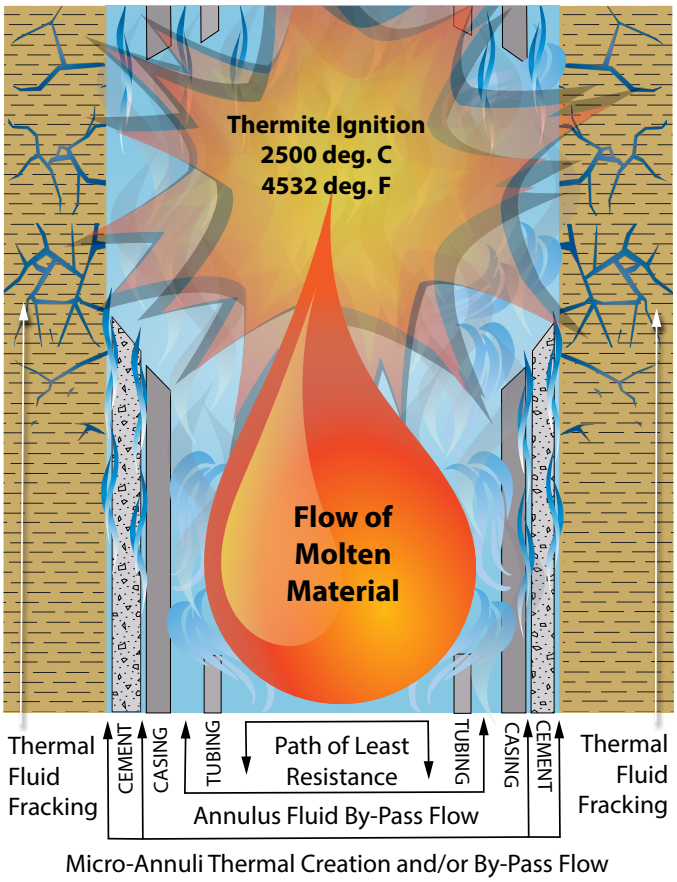


Figure 59 - Thermite Tear-drop Effect

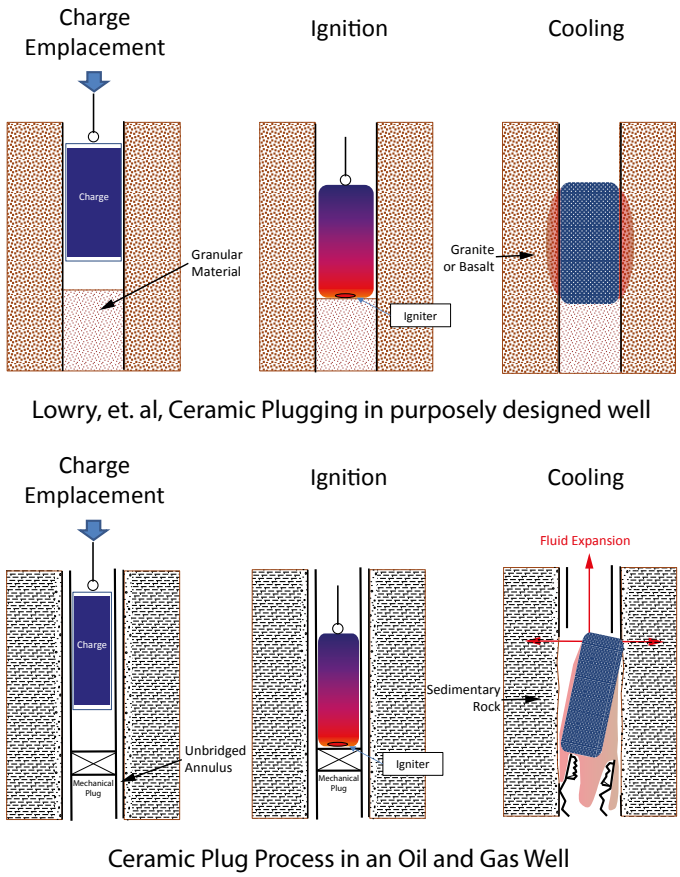


Figure 60 - Thermite Plugs in Oil and Gas Wells

Compare your method with Thermite P&A

The two methods are not mutually exclusive as they can be combined to provide a cost effective solution.

Within social media, where scientific evidence is not necessarily pertinent, thermite may be an appealing solution that removes the thought process by annihilating the well bore but, unfortunately, the uncontrollable nature of thermite can make it a problem and not a solution for thru-tubing thermite burning temperatures of 2,500 deg. C, as shown in Figure 59.

Lowry[31] , et al., teach a controlled self-sintering ceramic plugs, which are placed in an open granite or basalt bore on top of a granular material filled borehole. Unfortunately, oil and gas wells are predominately in porous sedimentary rock with potentially high fluid content, wherein economic use of such a plug requires thru-tubing placement.

A shown in the lower part of Figure 60, oil and gas through-production-tubing "thermite only plugging" may require larger quantities of thermite to bridge large annuli gaps to melt a large volume of surrounding rock.

Rapid and extreme expansion of superheated trapped annuli and rock fluids could burst casing and fracture rock before being displaced upward or outward as molten material travels downward to create additional annuli and leak paths around the perimeter of the well bore.

Provided fluids are allowed to spew from the top of the well, aging and decrepit wellhead equipment may, for the most part, avoid being burst or blown from the well when igniting large quantities of thermite.

Oilfield Innovations applauds Lowry's and his co-contributors' work and believe that it may be a valuable contribution, wherein the combination of a self-sintering ceramic plug process with our compaction method may mitigate the risks and provide a viable solution.

Our method of tubing compaction could remove the tubing and associated annuli gaps through which thermite might fall. It also allows logging the condition and fluid content of the surrounding geology to measure whether a ceramic plug can be welded to the cap rock without fracking. Finally, our piston supported by compacted tubing could be composed of a Kevlar bag of granular sealing material that provides a fireproof base for backfilled granular materials needed to hold and weld a self-sintering mix of thermite and inert materials to the rock of the well bore.

Accordingly, Oilfield Innovations method could be used to enable use of thermite ceramic plugs within oil and gas wells.