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PLUGGING & ABANDONMENT TECHNIQUES FOR OFFSHORE WELLS

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Undergraduate Project submitted to the Petroleum Engineering Course of the Federal University of Rio de Janeiro as a partial fulfillment of the requirements for the degree of Petroleum Engineer.

Advisor: Ilson Paranhos Pasqualino

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Técnicas de Abandono Permanente para Poços *offshore*

Tatiana Vieira do Paço Hallak

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Curso: Engenharia de Petróleo

Projetos de campos de hidrocarbonetos são desenvolvidos para terem um longo ciclo de vida. As atividades de produção se iniciam com a descoberta de reservatórios de petróleo e podem se extender por décadas. Quando as reservas economicamente recuperáveis já foram extraídas e o fluxo de caixa proveniente da produção não é mais atrativo, a fase de abandono se inicia. Este trabalho está focado na fase de abandono, mais especificamente nas técnicas de abandono permanente de poços *offshore* no Brasil. O abandono permanente ocorre com a implementação de um conjunto de barreiras permanentes quando não há interesse de reentrada futura. As técnicas de abandono permanente visam o isolamento dos fluidos do reservatório para que não migrem ao longo do tempo e contaminem outras formações, aquíferos ou a superfície, apresentando uma perspectiva de abandono eterno. Este trabalho analisa as melhores práticas da indústria em conjunto com as regulações brasileiras e normas internacionais.

Palavras-chave: Abandono Permanente de Poços, Técnicas de Abandono, Barreiras Permanentes, Descomissionamento.

Abstract of the Undergraduate Project presented to POLI/ UFRJ as a partial fulfillment of the requirements for the degree of Engineer.

Plugging & Abandonment Techniques for Offshore Wells

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Advisor: Ilson Paranhos Pasqualino

Course: Petroleum Engineering

Hydrocarbon field projects are structured to have a long life. Starting with the discovery of petroleum reservoirs, production activities are typically performed throughout decades. The abandonment phase occurs when economically recoverable reserves have been extracted and the cash flow generated from production is not attractive anymore. This work is focused on the abandonment phase, specifically the permanent well abandonment of offshore wells in Brazil. The permanent well abandonment procedure comprises the establishment of permanent well barriers that aim to prevent the reservoir fluids from migrating up hole and possibly contaminating other formations, fresh water aquifers or the surface. This work analyses the best practices of the industry implemented worldwide and an overview of the Brazilian regulation and international guidelines.

Key-words: Permanent Well Abandonment, P&A Techniques, Permanent Well Barriers, Decommissioning.

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ALARP - As Low As Reasonably Practicable

ANP - Brazil's National Agency of Petroleum, Natural Gas and Biofuels

API - American Petroleum Institute

ASV - Annular Safety Valve

BHA - Bottomhole Assembly

BOP - Blowout Preventer

CBL - Cement Bond Log

DHSV - Downhole Safety Valve

ECD - Equivalent Circulating Densities

FBP - Formation Breakdown Pressure

FCP - Fracture Closure Pressure

FPP - Fracture Propagation Pressure

GBS - Gravity Base Structure

HSE - Health, Safety and Environment

HXT - Horizontal Christmas Tree

IBP - Brazilian Institute for Oil, Gas and Biofuels [*Instituto Brasileiro de Petróleo, Gás e Biocombustíveis*]

LOP - Leak-off Pressure

LOT - Leak-off Test

MD - Measured Depth

OBM - Oil Based Muds

OGUK - Oil & Gas UK or The United Kingdom Offshore Oil and Gas Industry Association Limited

P&A - Plug and Abandonment

PWC - Perforate, Wash and Cement

SGIP - Well Integrity Management System [*Sistema de Gerenciamento da Integridade de Poços*]

SPF - Shots per Foot

SSSV - Subsurface Safety Valve

TCP - Tubing-conveyed Perforating

TOC - Top of Cement

UKCS - The United Kingdom Continental Shelf

USIT - Ultrasonic Imager Tool

VDL - Variable Density Log

VXT - Vertical Christmas Tree

XLOT - Extended Leak-off Test

WBE - Well Barrier Element

WBS - Well Barriers Schematics

WBM - Water Based Mud

1. Introduction

Hydrocarbon field projects are structured to have a long life cycle. Starting with the discovery of petroleum reservoirs, production activities are typically performed throughout decades. From exploration to abandonment, five main stages can be distinguished in the life of oil and gas fields: exploration, appraisal, development, production and abandonment.

This work is focused on the abandonment phase, specifically the permanent well abandonment operation. The purpose of well plugging and abandonment activities is to isolate the reservoir fluids within the wellbore and from the surface or seabed. Permanent well abandonment is considered one of the most delicate and expensive stages of a decommissioning project.

The offshore decommissioning topic has been widely discussed worldwide and international guidelines have been created to provide standard requirements for the industry. It is considered a relatively new activity in Brazil where decommissioning procedures are still being established by regulatory agencies. Since more than half of the offshore production platforms in Brazil are reaching the end of their productive life, it is clear that the country is entering into a decommissioning phase. The work proposal is presented in chapter 1.6.

1.1 Exploration

The exploration phase provides the information required to exploit the best opportunities in the acquired blocks. A geophysical exploration project starts with fieldwork and ends up with constructing the subsurface geological model of the area.

The starting phase is the data acquisition, when geophysical measured values are recorded through standard field procedures. The main exploration methods employing geophysical principles are seismic, gravity, magnetic, electrical, radioactivity and electromagnetic [1]. Following data gathering, there is a data processing phase which aims to assess the quality of the data recorded, leading to corrections and enhancing of the geophysical signal. The third phase is the interpretation of the final processed data in order to extract the geological model of

the subsurface area under exploration. The geological history is then studied and the likelihood of hydrocarbons being present is quantified.

The drilling of an exploration well and the obtained drilling and logging data provide valuable information regarding the properties of rock formations, their minerals and fluid contents. Drilling parameters such as drilling rate indicates the physical nature of rocks penetrated by the drill bit. In addition, the circulating drilling mud can carry components that will suggest the presence of hydrocarbons.

The geologists study the rock cuttings and cores to understand the rock lithology, composition, stratigraphic arrangement and thickness of penetrated rock formations. Electronic tools are run and well logging is performed to obtain a record of a formation´s rock properties. The well logs generated are a graphic image of geophysical data as function of wellbore depth and the parameters are measured by resistivity logs, radioactivity logs, sonic logs and porosity logs. A composite well log indicating very high resistivity zone may denote a hydrocarbon rich section which is emphasised in the red encircled portion of the Figure 1.

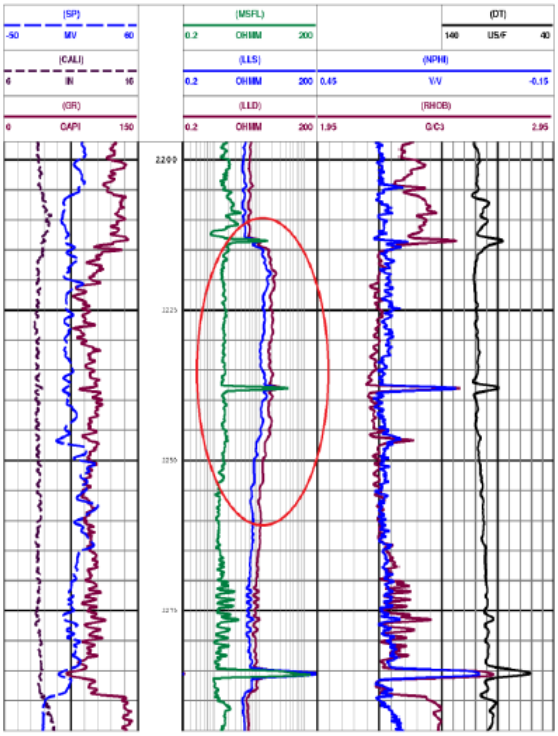


Figure 1: Composite Well Log [2]

1.2 Appraisal

When the results of the exploration well confirm the discovery of potentially viable oil and gas sources, the next stage is to drill appraisal wells. The appraisal wells aim to assess more precisely some characteristics such as the size of the reservoirs, the volume of the natural mineral resources available and the quality and extent of the geological play. The larger and more complex the reservoir, the more appraisal wells are needed. Therefore, results from appraisal wells are essential to decide whether it is worth developing the field.

In case it is concluded that the field development is not commercially viable due to an insufficient amount of hydrocarbons, the appraisal wells will be plugged and abandoned.

1.3 Development

Development strategies for new fields are based on data obtained from exploration and appraisal phases. A field development plan comprises all activities and processes required to develop a field. This phase is extremely complex due to its amount of variables to be considered. The variables are related to geological parameters, recovery methods, location of production and injection wells, number of production and injection wells, injection patterns, types of wells, drainage areas, well completion, artificial lift methods, types of production units, production unit location, subsea infrastructure, flow assurance, gathering system, control systems, surface facilities design, export methods, time required for construction and commissioning, among several other decisions.

Initial development plans are defined through simulation studies considering either deterministic or probabilistic approaches to rank options using economic indicators, availability and risk assessment [3]. In the preparation of development plans, field management decisions are usually made using a deterministic approach. Probabilistic procedures are used in some cases for reserves assessment considering geological uncertainties, or in the field evaluation incorporating economic uncertainties [4].

The aim of this phase is to develop an optimised strategy for hydrocarbon production in order to enhance the recovery factor from the reservoirs. In this regard,

economic evaluations are made. If the required economic criteria are met, the field is developed and then produced.

1.4 Production

The production phase is when revenue is generated for the first time in a project. By this time, the field development has been completed and the first oil barrel has been produced from the field.

The lifetime of a reservoir is made of successive phases. It starts with a period of production increase when natural pressure mechanism from reservoir is strong enough to enable fluids to be produced from wellbore to surface conditions. It is followed by a stable phase, then injection phases to increase oil recovery and ultimately depletion period when hydrocarbon production declines progressively.

The knowledge about which drive mechanism controls fluid behaviour within reservoirs is essential for a proper understanding of reservoir performance. The drive mechanisms that provide natural energy necessary for oil recovery are solution gas drive, gas cap drive, water drive, gravity drainage drive and combination drive [5].

In addition, artificial lifting is also considered to obtain higher production rates. The differential pressure between average reservoir pressure and flowing bottomhole pressure is named drawdown and enables the fluids to be transported towards and out of production wells. Artificial lift methods are used to lower the flowing bottomhole pressure of the well which means that the differential pressure will increase and then production rates will be higher. The main artificial lift methods are gas lift and pumping (e.g. subsea boosting, beam pumping, electrical submersible pumps).

After initial production, oil reservoirs start losing the natural drive mechanism that forced production fluids to the surface. Hence, some recovery methods can be pursued in which external fluids are injected into a reservoir to maintain reservoir pressure and to sweep hydrocarbons ahead of the injected fluids. Gas flooding, waterflooding and WAG (i.e. water-alternating-gas) are techniques that can be implemented using injection wells. Furthermore, the WAG recovery method has been successfully used on Brazil's pre-salt fields. Waterflooding method is capable of displacing oil from injector wells towards the wellbore and gas flooding is considered

a secondary recovery method when the gas injected is not miscible with or dissolved in oil, otherwise it is considered an enhanced oil recovery method [6].

Enhanced Oil Recovery represents a technique that results from the injection of gases, liquid chemicals or thermal processes to recover additional hydrocarbon volumes from the reservoir. The injected fluids or processes interact with the reservoir rock and oil system to create conditions favourable for oil recovery. These interactions might, for instance, result in oil swelling, oil viscosity reduction, wettability modification or favourable phase behaviour. Enhanced oil recovery methods are classified as thermal, chemical, miscible or microbial [3].

1.5 Abandonment

Abandonment phase is part of a normal life cycle of every oil and gas field. It is the stage when economically recoverable reserves have been extracted and the cash flow generated from production is not attractive anymore.

As an asset approaches the end of its life, a clear transition from the operational to the decommissioning phase must be implemented. Since the abandonment phase implies huge costs, companies try to extend a field´s life for as long as possible by a combination of efficiency improvements and cost reduction methods. This process is strictly regulated by international and regional legislations as well as the internal policies of each company. The abandonment options that will be pursued depend on the location of the offshore facility and subsequent legislations.

Any decommissioning project has a multidisciplinary approach focused on assessing all feasible abandonment options, risks and costs. This is pivotal to create a collaborative environment, engaging with different stakeholders, partners and regulatory agencies during the planning and execution phases of abandonment.

1.6 Work proposal

This work was developed to assess the best practices of the industry related to permanent well abandonment techniques. An overview of the requirements issued by the Brazilian regulation, and also international guidelines from Norway and the United Kingdom are presented on this work.

The structure of this work starts with Chapter 1 that introduces the idea of an oil and gas field's life cycle, explaining its different stages from exploration to abandonment. Chapter 2 provides an overview of the offshore decommissioning sector, the high expenditures related to it and the substantial amount of offshore structures reaching the end of their productive life. The concept of plugging & abandonment of wells is presented in Chapter 3 showing a comparison of the total expenditure among all decommissioning activities. The Brazilian regulation and the international guidelines used as reference are all presented in Chapter 4 that is followed by Chapter 5 explaining the well barrier requirements according to each guideline. Chapter 6 presents the definition of internal and external barriers of the wells and also how they can be verified. The different plugging materials that could act as an alternative to conventional cement are presented in Chapter 7. Although each well is unique and has a particular abandonment approach, Chapter 8 provides the steps of a general plugging & abandonment procedure for offshore wells. Chapter 9 aims to present the available techniques that are already implemented worldwide and after all the research, Chapter 10 provides recommendations for the industry regarding issues that can be avoided during abandonment phase. The conclusion of this work is presented by Chapter 11.

2. Offshore decommissioning

Decommissioning is defined as the dismantling, decontamination and removal of structures, equipment and facilities from the asset location. Each decommissioning project is unique since each production system has its own challenges to be overcome.

The need to decommission an offshore production unit is initiated when the design life has been exceeded and there are integrity risks, when facilities are of no further use due to the oil field being depleted or when oil production is no longer economically viable [7]. The oil price is also an essential parameter to evaluate whether the field should be decommissioned or not.

The offshore decommissioning topic has been widely discussed within the petroleum industry due to a substantial amount of offshore structures reaching the end of their productive life. Discussion is based on finding the right balance between technical feasibility, integrity issues, health and safety, environmental.

The decommissioning phase must be extensively planned. It requires a multidisciplinary approach, as seen in Figure 2, with several technical assessments and creates challenges for accurately estimating costs due to several uncertainties. Therefore, planning for decommissioning needs to start well before the end of the field´s life.

The process of decommissioning is strictly regulated by a range of national legislations and international agreements that were created over the years to provide standard guidelines for the oil and gas companies. The definition of the decommissioning approach to be used is typically a balance of regulatory requirement, environmental impact, energy use, gaseous emissions, technical feasibility, cost, social impact, public opinion, health and safety.

2.1 Worldwide overview

More than 7,000 offshore oil and gas installations are currently in place worldwide and many of them will be decommissioned in the future. It is believed that over 600 offshore projects will be decommissioned in the next five years [8]. The decommissioning sector is increasing all over the world and firms focused on developing an expertise in this complex and multidisciplinary area will be able to take full advantage of this significant economic opportunity.

Although North America is the largest market for decommissioning, the highest spending for offshore decommissioning is in Europe because of the size and volume of its structures. It is believed that Mexico and Brazil will be the focus of decommissioning demand in Central and South America. Angola and Nigeria will drive this spending in Africa while Australia will drive demand in Asia-Pacific region [8].

The United Kingdom, Norway, Denmark and the Netherlands are the four countries with oil and gas resources rights in the North Sea. Market forecasts reveal that North Sea decommissioning expenditure can reach from £1.9 billion to £2.5 billion per year over the next five years. Regarding the North Sea decommissioning market, the UK Continental Shelf (UKCS) is expected to be the largest sector until 2020 when Norway is likely to have the highest expenditure as presented in Figure 2 [9].

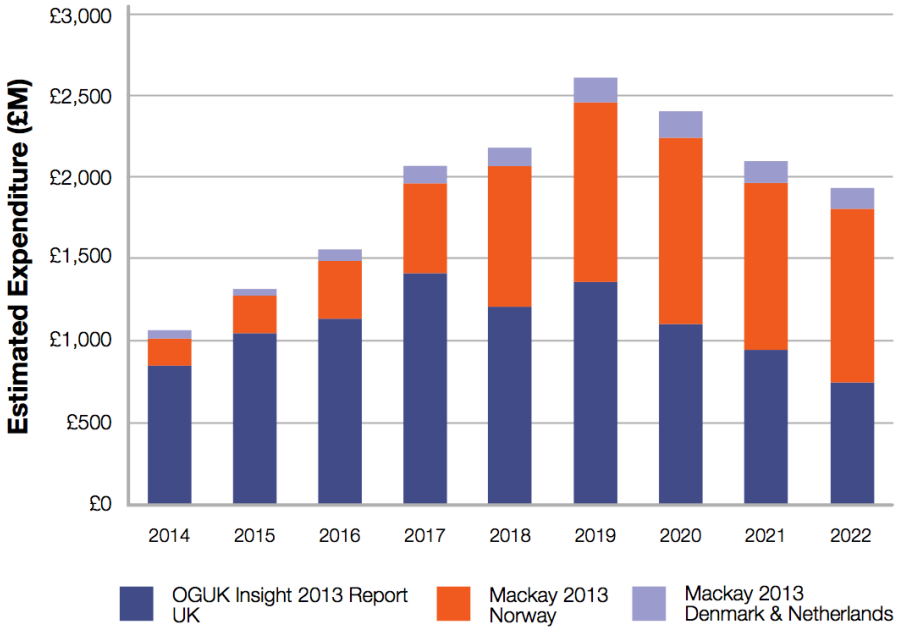


Figure 2: Annual estimated North Sea decommissioning expenditure [10].

The Brent field, discovered in 1971, is one of the largest hydrocarbon fields on the UKCS and the most iconic one since it lends its name to the Brent Crude price benchmark. The field is currently being decommissioned after 40 years of operations and around three billion barrels of oil equivalent produced. It was served by four enormous platforms, Brent Alpha as a steel jacket and Brent Bravo, Charlie and Delta

as concrete gravity base structures (GBS). Figure 3 shows a comparison between the four structures.

Figure 3: Brent field installations [11].

The decision to decommission was made since most part of its economically recoverable reserves has been extracted. As the operator of the Brent field, Shell submitted Decommissioning Programmes to the UK Department for Business, Energy and Industrial Strategy in accordance with the Section 29 of the *Petroleum Act* 1998. Since the Decommissioning Programmes from Brent field are available for public consultation, they are a source of knowledge for this work.

Due to the long history of offshore oil and gas exploration in the Gulf of Mexico´s Outer Continental Shelf, the experience led to industry wide standards for decommissioning offshore facilities. The Gulf of Mexico is considered the largest region when it comes to offshore decommissioning. The region has the most diverse and competitive decommissioning market with legislations and requirements being very well established by regulatory agencies to ensure they are met by operators.

2.2 Brazilian perspective

Aged platforms pose an environmental threat since they are designed to operate safely for a certain lifetime and risks of accidents increase over time. Brazil had a total of 147 offshore units in 2015 as represented in Figure 4. Among them, 79 were being operated for more than 25 years, 27 platforms had between 15 and 25 years of production while the remaining 41 were 15 years old or less. Since 54% of the

offshore installations in Brazil are more than 25 years old, there is no doubt the region has entered a decommissioning phase [12].

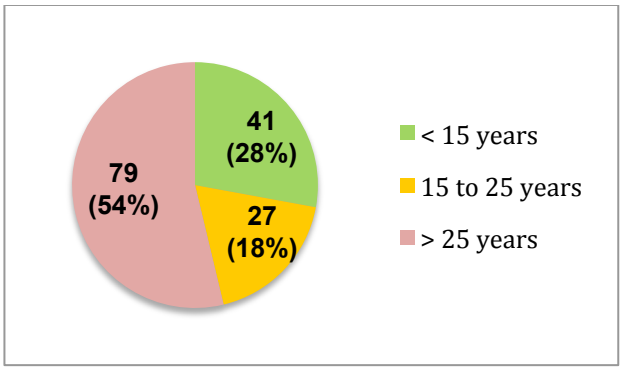


Figure 4: Age and quantity distribution of Brazil offshore production platforms in 2015 [12].

Petrobras, the Brazilian oil and gas corporation majority-owned by the state, recently created a team to manage its decommissioning projects. Due to having 74 platforms that are in operation for more than 25 years, the goal of the company is to develop an integrated approach focused on optimising decommissioning activities.

Brazil´s National Agency of Petroleum, Natural Gas and Biofuels, also known as ANP, is the regulatory agency in charge of issuing resolutions and norms to oversee activities undertaken by the oil, natural gas and biofuels sectors in the country. The Law 9478/97 states that ANP is responsible for regulation, contracting and monitoring of the economic activities related to the oil and gas industry in Brazil.

The decommissioning of offshore systems is considered a relatively new activity among the offshore oil and gas industry, especially in Brazil where the decommissioning procedures are still being established. The concern about not having clear legal requirements regarding offshore decommissioning has already been addressed by Petrobras and other operators. The need to develop guidelines to meet future increases in demand is pivotal to the offshore industry in the country.

3. Plug & abandonment of wells

Offshore wells can be either platform or subsea wells. Platform wells are those with their wellhead located in a platform, thus equipped with a conventional or dry Christmas tree. Subsea wells are those drilled from a mobile installation and tied back to a platform, their wellhead is on the seabed and they are equipped with a wet Christmas tree. This work is focused on the permanent abandonment of subsea wells only.

Permanent Plug & Abandonment (P&A) is the process by which a well is closed permanently using plugging materials and abandonment techniques. The purpose of a permanent well abandonment is to prevent pressure buildup or cross flow in the well and its surroundings by isolating all permeable hydrocarbon zones and water zones of different pressure regimes from each other and the seabed. Well abandonment is one of the most delicate stages of decommissioning projects since improperly sealed wells might be a threat to the environment.

It is estimated that in The United Kingdom Continental Shelf (UKCS), the expenditure in well abandonment operations will be maintained as the highest among all the other categories until 2022. In 2017, for instance, well abandonment operations comprised 46% of the total expenditure of the decommissioning projects as seen in Figure 5. The reason why the trends of spend proportion vary over time is because the project approach will also vary, covering early stage activities and then later activities such as monitoring [9].

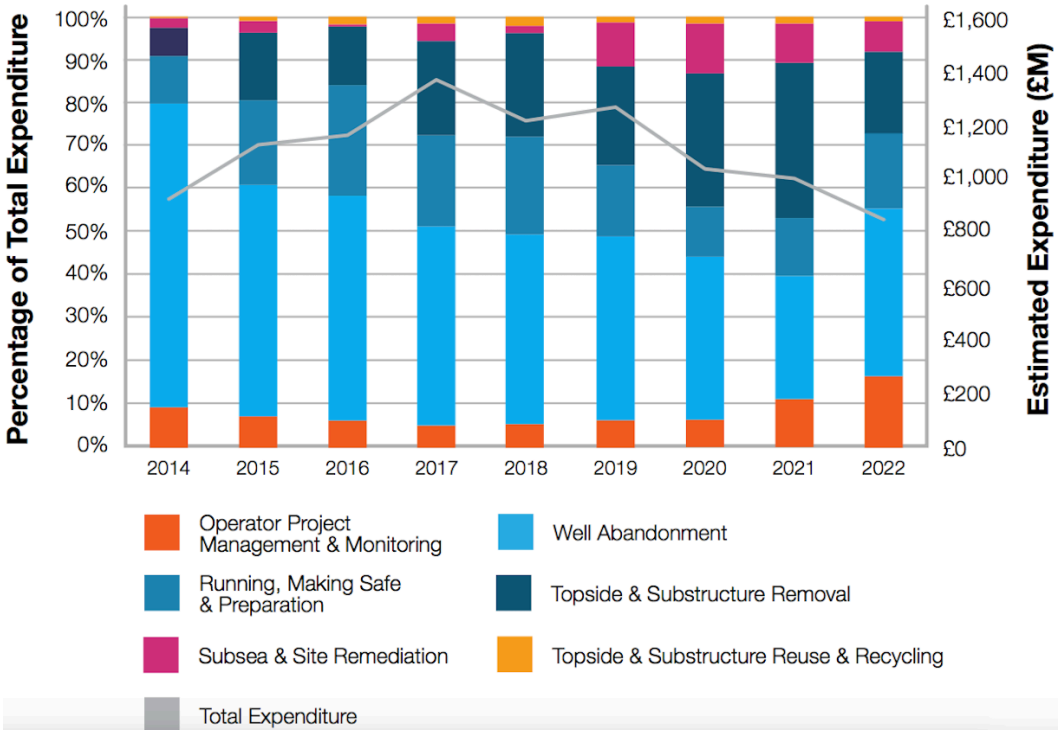


Figure 5: Estimated Annual UKCS Expenditure Breakdown [9].

In order to determine a proper P&A procedure, it is necessary to understand the current status of the well. Since this information depends on the quality of the data available, the age and history of the well, it can be challenging to make an accurate assessment and determine the most suitable abandonment approach. Some usual issues faced by the operators are the uncertainty related to the well status and the lack of evidence (e.g. cement bond logs) regarding the quality of annular barriers. Many projects are likely to encounter existing abandoned wells and information on the abandonment conditions of these wells are extremely difficult to obtain.

All wells must be plugged and abandoned in compliance with regulatory requirements when they are no longer in use and their connecting platform is being decommissioned. When the enterprise permanently abandons a well, there is a legal obligation to leave it in a condition that protects the downhole, the reservoir formation, aquifers and the surface environment.

4. Regulatory Context

Although procedures for decommissioning projects are in initial stages of development in Brazil, local authorities, regulatory and environmental agencies are working together with the oil and gas industry to define a clear methodology to be implemented in the country.

The completion of this work was simultaneous with the release of the Guidelines for Well Abandonment issued by IBP (i.e. Brazilian Institute for Oil, Gas and Biofuels) in August 2017. Therefore, the well abandonment requirements presented by this guideline were not included on this work. The Brazilian regulation and international guidelines used as reference are mentioned in chapter 4.1 and 4.2.

4.1 Brazilian Regulation

The Resolution No 46 issued by ANP in 2016 aims to replace the Resolution No 25/2002 and establish the technical regulation for the Well Integrity Management System, known in Brazil as SGIP (*Sistema de Gerenciamento da Integridade de Poços*). It states that the operator must guarantee that the permanent barriers implemented are following the best practices of the industry. The concept of ALARP (As Low As Reasonably Practicable) is introduced in the resolution. It is defined that efforts to reduce risks must be continuous until the point when the additional effort is not worth it, which means that the amount of time and resources used is much greater than the additional safety achieved.

The Guidelines for Well Abandonment issued by IBP in 2017 were developed in compliance with the Brazilian regulation and the best practices of the industry. They were carefully prepared to ensure that the well abandonment operation in Brazil is performed following the best standard. Moreover, they provide a full guidance adapted to the Brazilian scenario with the same quality of the international guidelines. As mentioned previously, these guidelines were not included as reference on this work due to being released simultaneously to the completion of this work.

4.2 International Guidelines

Different countries establish specific requirements and procedures for well abandonment. There is a range of international frameworks and conventions available for consultation, this chapter aims to provide an overview of guidelines that specifically cover well abandonment procedures and that were used as reference throughout this work. Therefore, they can be implemented in P&A projects in Brazil as a support for decision-making processes related to selecting the most suitable abandonment approach. The requirements for permanent well barriers are discussed in Chapter 5.1 of this work.

4.2.1 NORSOK Standard D-010

NORSOK Standard D-010 is considered the only holistic well integrity standard in the world. It was developed by the Norwegian petroleum industry as an initiative to address well integrity throughout the life cycle of the well from its construction to abandonment. The original guideline was issued in 2004 and its revision was published in 2012. This standard focuses strongly on the establishment of well barriers and their elements and is a result of continuous cooperation between Norwegian based operators and service companies.

4.2.2 Oil & Gas UK

The Guidelines for Suspension and Abandonment of Wells issued by OGUK (Oil & Gas UK or The United Kingdom Offshore Oil and Gas Industry Association Limited) is considered to be the industry-wide standard for well abandonment in the United Kingdom. Its latest revision was published in 2015 and is currently employed worldwide as a support for P&A activities.

5. Well Barriers

The well barriers must ensure full and adequate isolation of permeable formation fluids and sources of outflow both within the wellbore and from the surface or seabed. A permeable zone is considered as any zone in the well where there is a chance of fluid displacement on application of pressure differential.

The barriers are part of every stage of the well's life from drilling to completion, to production and to abandonment. While well barriers are defined as isolations that prevent flow from a source and are established by the use of well barrier elements (WBEs), the elements from a permanent well barrier shall also, individually or in combination, create a seal with eternal liability.

Permanent plugged wells must be abandoned with a lasting perspective considering the effects of any foreseeable chemical and geological processes. NORSOK D-010 Rev.4 [13] and ANP`s Resolution 46/2016 [14] state that control cables and lines must be removed from the intervals where permanent well barriers are set since they can create vertical leak paths through the barrier.

Regarding the setting of a surface plug, Brazilian regulation requires that it is mandatory only in case there is a removal of the wellhead or if the casings or conductor are cut.

The Brent field Decommissioning Programme issued by Shell in 2017 presented a P&A philosophy about well monitoring. It states that after setting the permanent well barriers, each well must be monitored for a minimum period of 90 days to assess any potential build-up of pressure and the composition and flow rate of any fluid. The wells were fitted with a suspension flange (a cap that is put on the top of the well while suspended) and pressure gauges to allow the pressure monitoring in order to confirm if the well was stable after the 90-day period.

5.1 Requirements of permanent well barriers

A permanent well barrier must be placed adjacent to an impermeable formation and must extend across the full cross section of the well, including all annuli and seal in both vertical and horizontal directions as presented in Figure 6.

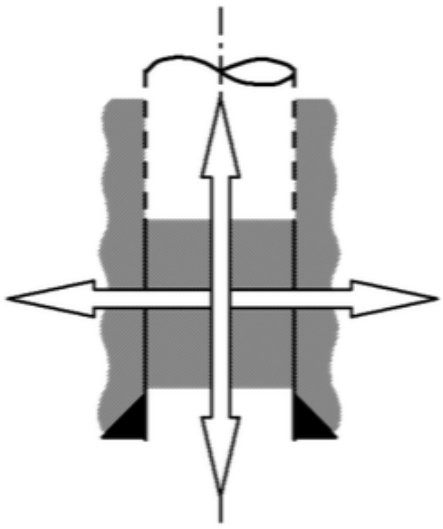


Figure 6: Well barrier extending across the full cross section of the well with both vertical and horizontal seal [13].

5.1.1 Number of well barriers

The number of well barriers required by NORSOK D-010 is described in Table 1 and the requirements from ANP`s Resolution 46/2016 are similar. The definition of over pressured zones is related to the zones that have a pore pressure above the normal regional hydrostatic pressure.

Table 1: NORSOK D-010 requirements for number of well barriers [13].

Number of well barriers:	**Circumstances:**
Minimum 1 barrier	- If the reservoir formation has no potential of flowing; OR - If there is undesirable crossflow between different zones;
Minimum 2 barriers	- For reservoir formations or zones with a potential risk of hydrocarbons flow; OR - For over pressured zones with a potential risk of any kind of fluid flow

Although definitions may vary from operator to operator, a common procedure typically used by industry states that at least two tested independent barriers must be in place at all times. The primary well barrier is defined as the first barrier of the well against potential source of inflow. Its objective is to isolate the reservoir and existing accessible wellbores to prevent fluid displacement from reservoir into shallower permeable formations or to the seabed. The secondary well barrier also provides the isolation of zones with flow potential from the surface. In addition, it acts as a backup to the primary well barrier.

5.1.2 Material Requirements

NORSOK Standard D-010 Rev.4 [13] recommends that a permanent well barrier should have the following characteristics:

- Provide long term integrity;
- Impermeable;
- Able to withstand mechanical loads;
- Adherent to the casings and reservoir formations around them;
- Resistant to chemicals and substances such as H_2S, CO_2 and hydrocarbons;
- Non-shrinking;
- Wetting to ensure bonding to steel;
- Not harmful to the integrity of steel tubular.

Even though it is not specified which materials must be used, the plugging materials should fulfill the characteristics above. Some alternatives to cement are presented in Chapter 7.

Furthermore, it is also stated by NORSOK D-010 that elastomer seals used as sealing components are not considered permanent barriers elements.

5.1.3 Position requirements

The position requirements presented in this chapter were obtained from the guidelines for the suspension and abandonment of wells issued by Oil & Gas UK [15,16].

It is required that the first barrier must be set across or above the highest point of potential inflow which can be the top permeable zone or top perforations, the chosen point must be the shallower one. When it is set inside a liner or casing, it should be also lapped by annular cement. If the base of the barrier is set significantly above the point of inflow, such as on top of the production packer, the formation fracture pressure at the base of the barrier should be greater than the potential internal pressure. Otherwise, fractures could be created into the formation inducing possible leak paths.

For the second barrier position, the same consideration is used. Thus, the base of the secondary barrier must be positioned at a depth where the formation fracture pressure is greater than a potential internal pressure. It is also possible to share the same barrier between zones as presented in Figure 7 where the second barrier of the permeable zone B is also the first barrier to permeable zone A.

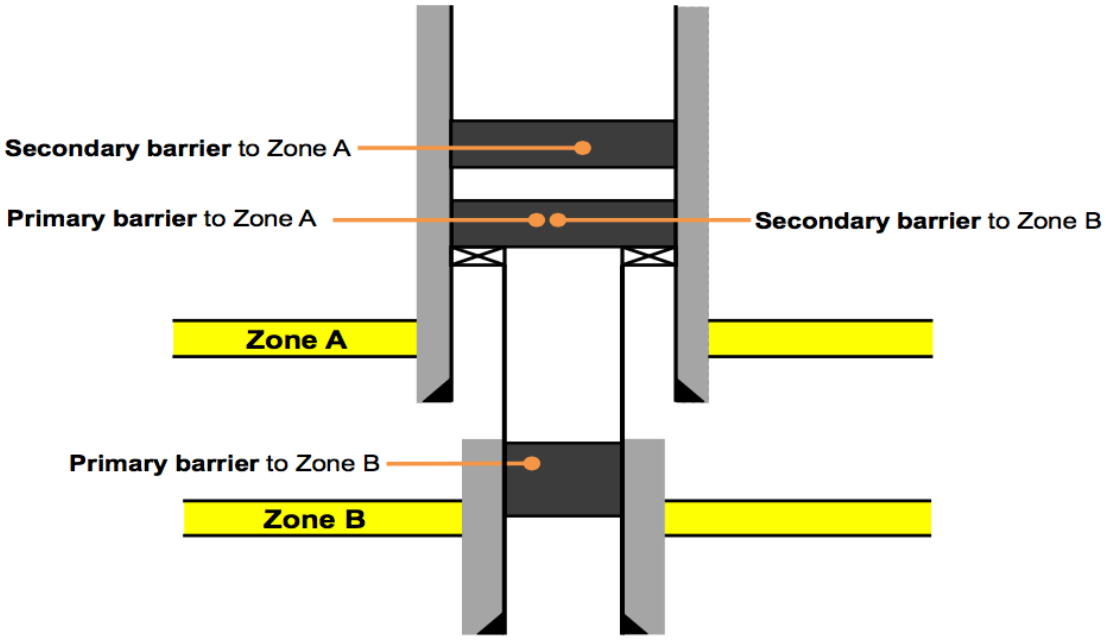


Figure 7: General requirements for well abandonment [16].

There are different methods that can be performed during drilling phases to evaluate the formation integrity. Data related to the formation fracture pressure is typically acquired by conducting a leak-off test (LOT). The minimum in-situ formation stress is determined by performing an extended leak-off test (XLOT), which is presented in Figure 8.

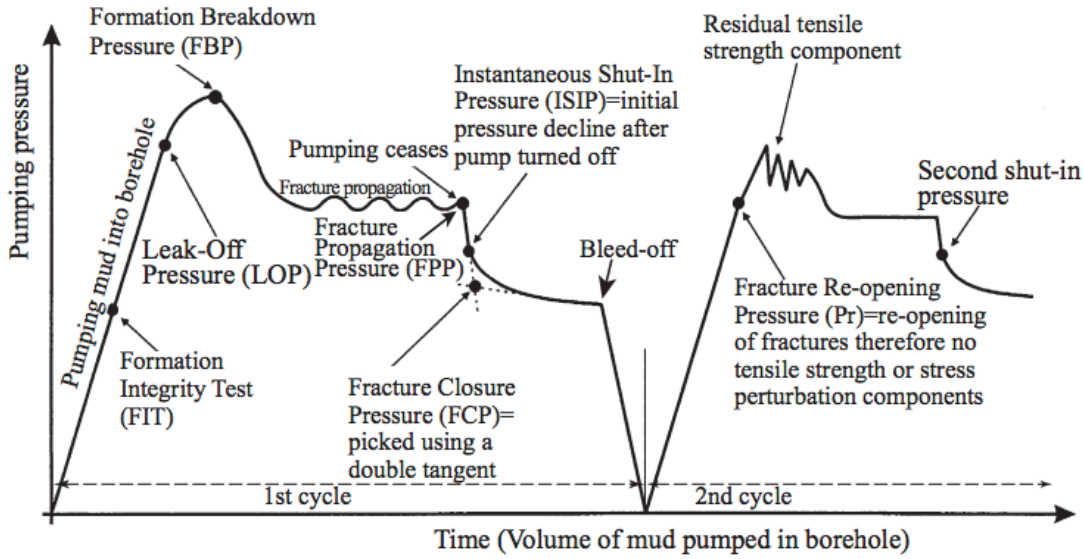


Figure 8: Relationship between pumping pressure and time or volume of mud injected during an extended leak-off test [17].

After each casing string is installed and cemented in place, LOT may be carried out to verify the integrity of cement at a casing shoe and to allow further drilling of the next open hole section. When the cement is hardened around the casing, the casing shoe is drilled into the new formation below the shoe. During LOT, the well is shut in and the wellbore is pressurised by mud injection at a constant rate. The initial linear slope is due to the compressibility of the drilling fluids in the wellbore. The leak-off pressure (LOP) is achieved when the pressure buildup deviates from the linear slope, then a fracture initiates at the wellbore interface and fluid begins to leak-off. Beyond this point, the pump is stopped and the pressure drop is observed [18].

During an XLOT, pumping is continued beyond the LOP. A pressure peak known as the formation breakdown pressure (FBP) is achieved and this creates a new fracture beyond the wellbore. Pumping is not ceased in order to propagate a stable fracture into the formation and it is only stopped when pressure is maintained at a stable fracture propagation pressure (FPP). As a result of flow-back, pressure will then decrease and the newly created fractures will close again. Hence, this will be the fracture closure pressure (FCP) and represents the minimum principal stress in the formation. Additional cycles are conducted to assure XLOT accuracy [19].

To sum up, the base of the barriers will be set at a depth taking into account FBP, FCP and the potential internal pressure. The potential internal pressure is

calculated as the worst anticipated reservoir pressure minus the lowest anticipated fluid density of the abandonment period.

5.1.4 Length Requirements

Regarding the Brazilian regulation, even though the former Resolution No. 25/2002 provided length requirements, the latest Resolution No. 46/2016 does not provide specific information about the required length of the well barriers. Therefore, the requirements from NORSOK D-010 Rev.4 and guidelines for the suspension and abandonment of wells by Oil & Gas UK are the main references in this chapter. According to these guidelines, Table 2 presents the length requirements for the primary barriers placed in open hole or cased hole.

Table 2: Length requirements for the primary barriers placed in open hole or cased hole [13,16].

Plug type / Guidelines	NORSOK D-010	OIL & GAS UK
Open hole	- Minimum 100-meter MD length with at least 50 meters MD above any source of inflow/leakage point. - If the plug is set in transition from open hole to casing, it should extend at least 50 meters MD below the casing shoe.	- Minimum 30 meters (100 feet). - An additional permanent barrier must be set into the cased hole with a minimum length of 30 meters to fully isolate the open hole.
Cased hole	- Minimum 50-meter MD length if set with a mechanical plug as a foundation. Otherwise, 100-meter MD length.	- If verified by logging, minimum 30 m MD of good cement bond in the annulus is required. The internal cement plug must be adjacent to the annular good cement with at least 30 m MD of overlap.

Although Oil & Gas UK [16] considers that a cement column of minimum 30 meters (100 ft) measured depth (MD) of good cement is a good industry practice to constitute a permanent barrier, it also states that usually 150 m (500 ft) MD barriers are more appropriate. It is also recommended that the top of the first barrier should be at least 30 meters MD above the highest point of potential flow.

According to the guidelines from Oil & Gas UK [16], it is possible to use a combination barrier solution instead of a two-barrier solution as seen in Figure 9. In this case, a cement plug of at least 60 m (200 ft) MD of good cement is a permanent barrier although it is more reliable to set a 240 m (800 ft) MD barrier. The top of this barrier must provide at least 60 m MD of good cement above the top of the potential inflow zone. In addition, the cement plug set internally must be adjacent to the annular good cement in a cumulative distance of 60 m MD of overlap.

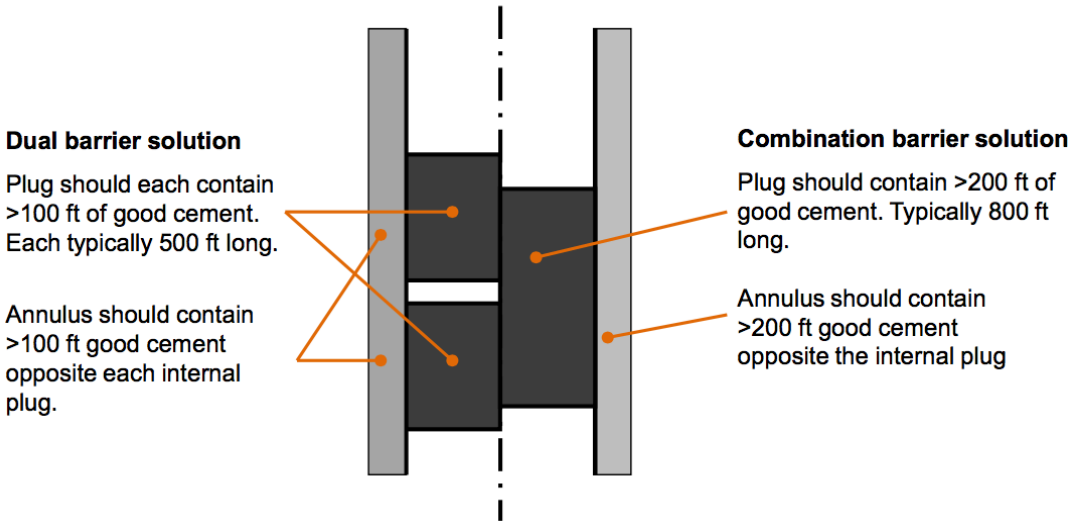


Figure 9: Comparison between dual barrier and combination barrier solutions [16].

5.1.4.1 Open hole

Permeable zones with different pressure regimes must be separated by one permanent barrier internally such as a cement plug inside the casing overlapping good annular cement. In Figure 10, there is an example of open hole permanent barriers when a potential internal pressure from the permeable zone exceeds the casing shoe fracture pressure. Therefore, two permanent barriers are required [16].

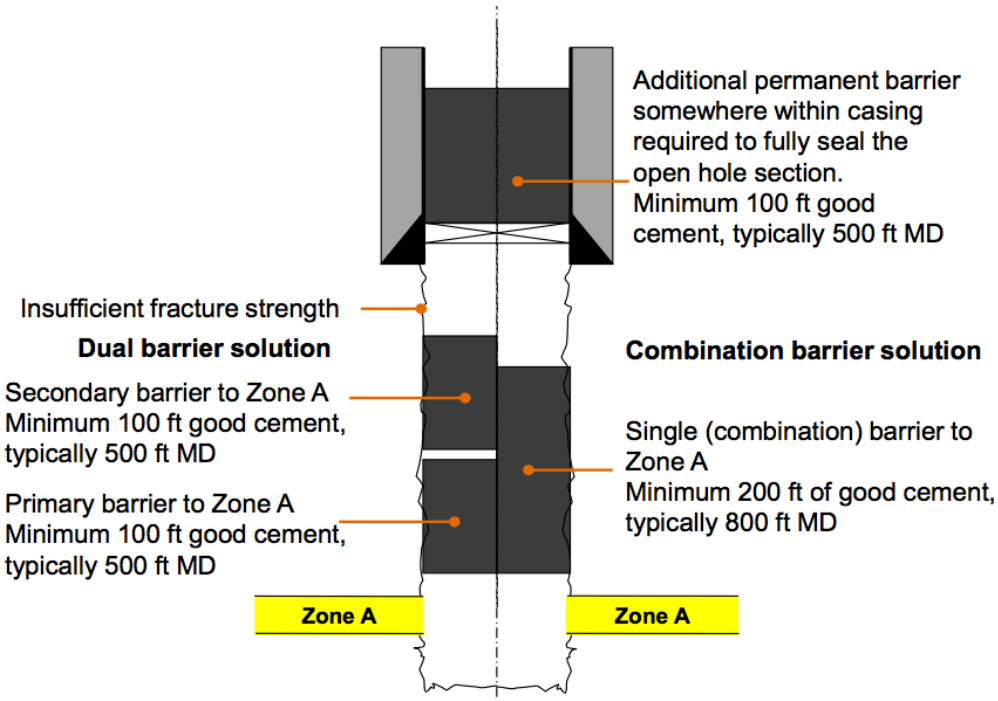


Figure 10: Open hole with two permanent barriers required [16].

Figure 11 illustrates the scenario of open hole where there are two permeable zones (A and B). Zone A requires isolation from zone B but the potential internal pressure from zone A is lower than the casing shoe fracture pressure; thus only one permanent barrier between them is required.

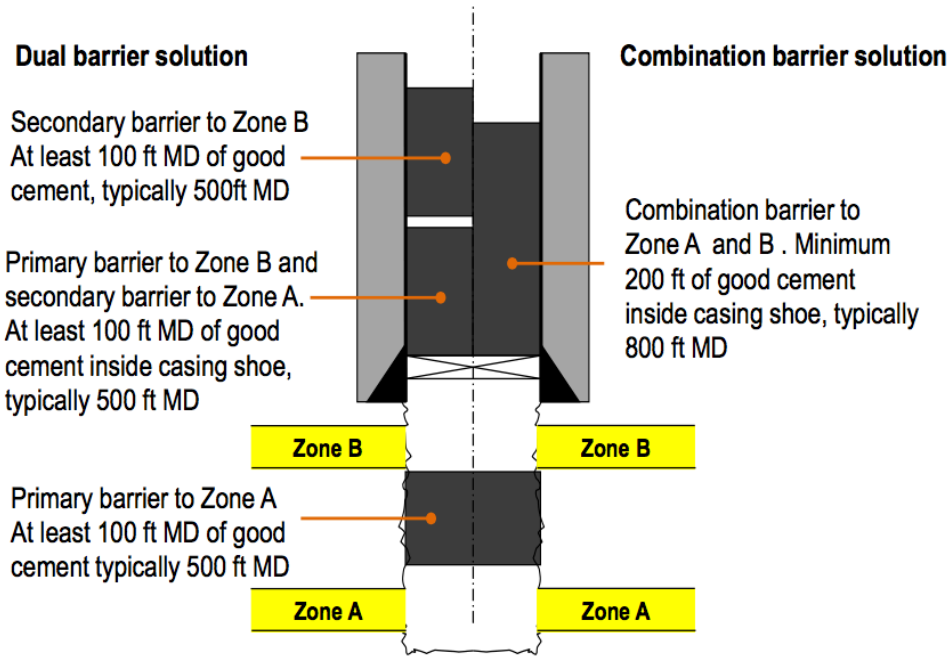


Figure 11: Open hole permanent requirements when only one permanent barrier is adequate [16].

The example in Figure 12 shows an abandonment option for the last open hole section of a wellbore. It was set an open hole cement plug across the reservoir as a primary barrier with a minimum 100-meter length and with at least a 50-meter cement column above the top of the reservoir. The secondary barrier is an additional cement plug set from the open hole into the casing with a length of at least 100 m, the base of the barrier must be at least 50 meters below the shoe casing and the barrier must have at least 50 meters inside the casing. The requirement is to have sufficient wellbore (formation) integrity at the base of both well barriers. It is considered in this example that casing cement has a minimum 30-meter length of verified logged cement.

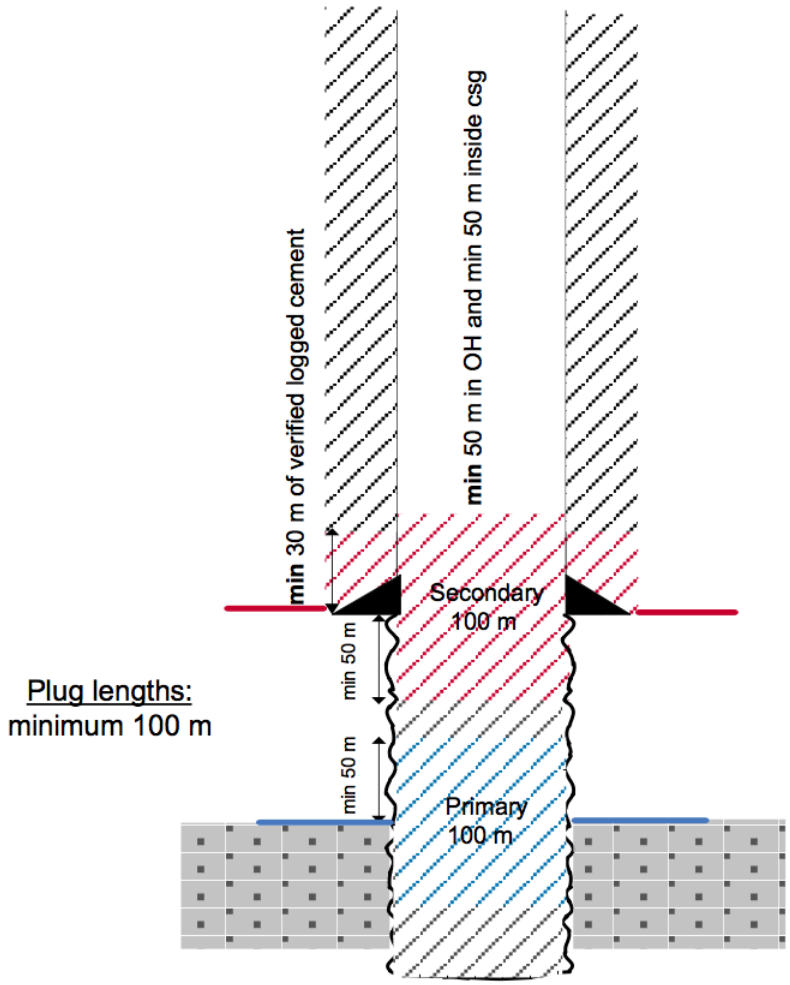


Figure 12: Plug and abandonment option for open hole section with inside casing plugs [13].

5.1.4.2 Cased hole

Although casing cement is considered a sufficient barrier to vertical flow in the annulus when there is confidence in the quality of the cement job, a cemented casing is not considered alone a permanent barrier to lateral flow into or out of the wellbore.

There are some tools to establish the existing top of cement (TOC) in the annulus. Some options are the use of logs such as cement bond logs or by record of parameters during cement operation. If the TOC was estimated based on differential pressure or monitored volumes measured during the original cement job, then a column of 300 m MD of annular cement above the base of the primary permanent barrier is required to ensure there is an annular cementation according to Oil & Gas UK. This requirement can be reduced or increased depending on how reliable is the level of TOC [15].

In the event of having insufficient cement behind the casing to provide a permanent barrier, some remedial cementing might be necessary. Some possible mitigation could be implemented by retrieving the casing, by section milling or by perforation as explained in chapter 9.

In Figure 13, there is example of a cased hole with two permeable zones in which cross flow is acceptable; thus no barrier is set between zone A and B. A mechanical plug was set in the production tubing and the primary permanent barrier set above the production packer. If the quality of the casing cement was not verified, then a 300-meter annular cement must be positioned above the base of the primary permanent barrier. A secondary barrier was placed above the primary one and a permanent barrier for shallow permeable zones was set across the conductor casing above a support to prevent slumping.

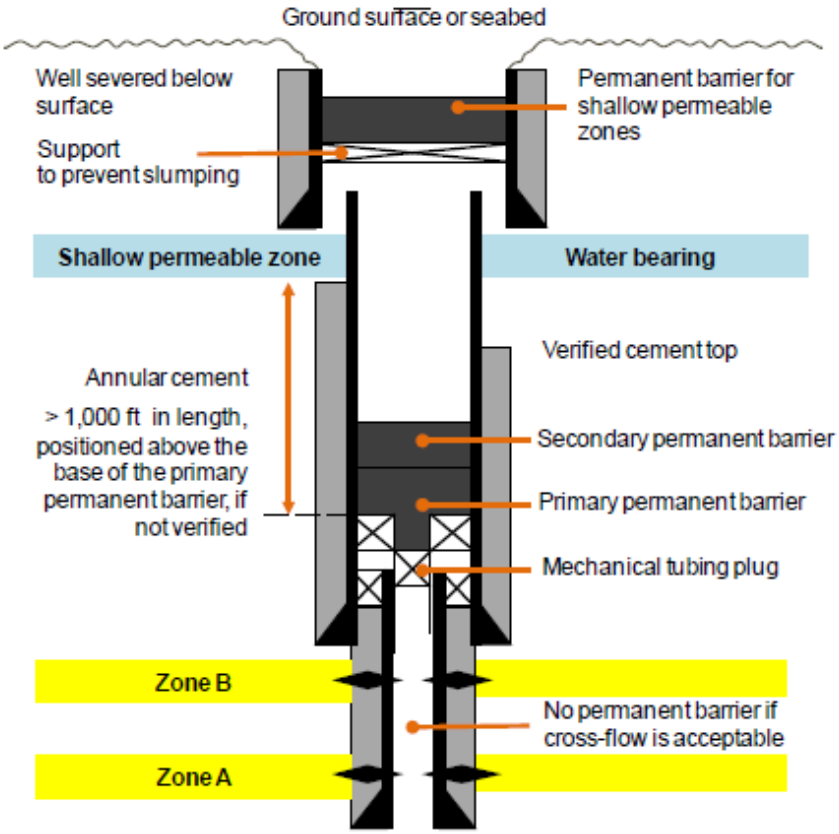


Figure 13: Cased hole abandonment schematic [16].

5.2 Well Barrier Schematics

NORSOK Standard D-010 [13] recommends that well barriers schematics (WBS) should be prepared to provide clarification about the well status and the presence of the primary and secondary well barriers. It is considered a practical method to easily illustrate the location of the barriers.

Prior to understanding the concept of WBS, it is important to know the location of the different types of casings that can be seen in Figure 14. The process of wellbore construction includes the depth to which casing must be set and there are four components: conductor, surface, intermediate and production casings.

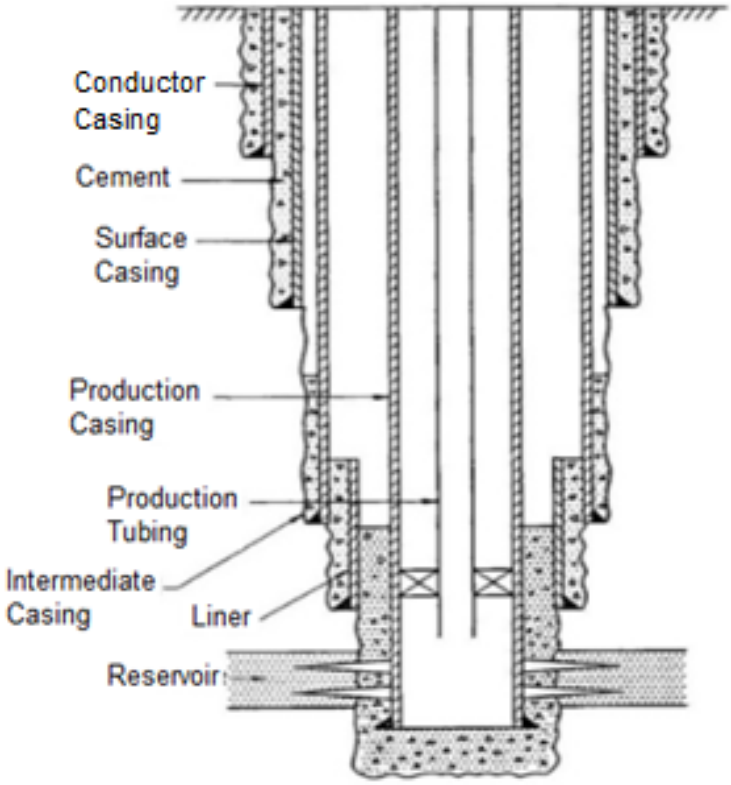


Figure 14: A typical casing program [20].

In Figure 15, there is a WBS for a permanent abandonment of a perforated well with its tubing being left in hole. The liner cement and the cement plug across and above perforations are the primary well barrier. As a backup to the primary barrier, there is the casing cement and the cement plug inside and outside of the tubing as elements of the secondary well barrier. In this scheme, there is also a greenish environmental isolation plug to isolate the full cross sectional wellbore, its elements are the casing cement of the surface casing and also a cement plug.

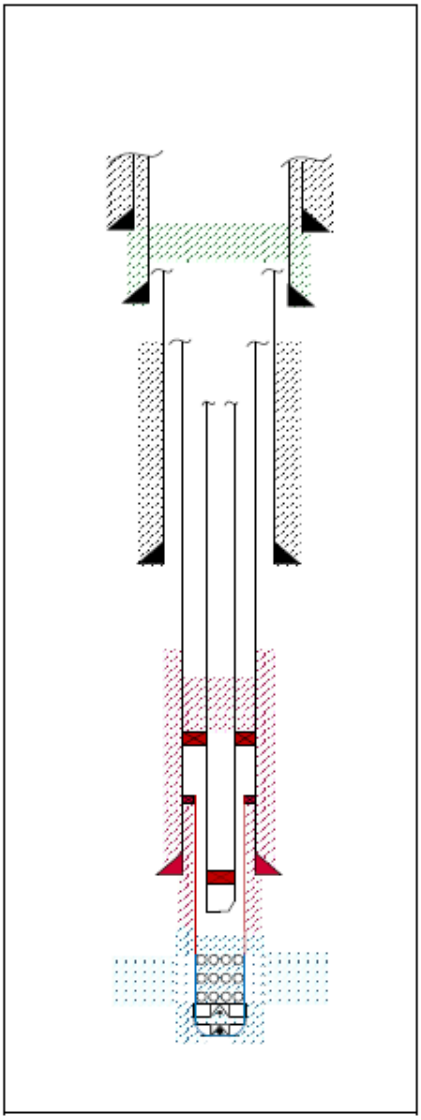


Figure 15: Well barriers schematics for a perforated well with a non-retrieved production tubing [13].

The WBS in Figure 16 represents a permanent abandonment of a perforated well with its production tubing removed. The primary well barrier is the liner cement and cement plug across and above perforations. For the secondary barrier, there is the casing cement and the cement plug across the liner plug. The environmental isolation plug is the same as the example above, a cement plug and the casing cement of the surface casing.

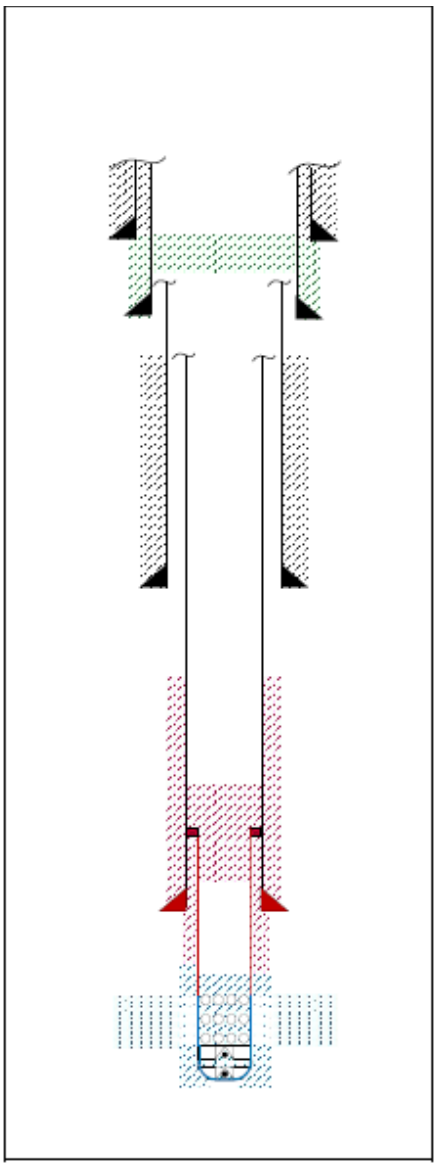


Figure 16: Well barriers schematics for a perforated well with its production tubing removed [13].

6. Verification of the well barrier

Both NORSOK D-010 and Oil & Gas UK recommends that any permanent barrier should be verified to guarantee

- It was placed at the required depth in order to have the required sealing capability.
- It can withstand the maximum potential differential pressure by a positive pressure test or an inflow (negative) test.

The tables in Appendix A aim to provide the verification requirements for well barriers set in different zones according to Oil & Gas UK [16].

6.1 Internal barrier

NORSOK D-010 [13] defines that the well barrier must have the ability to withstand a differential pressure ΔP = P1 - P2 when P1 is the potential pressure below the WBE and P2 is the one above the barrier as represented in Figure 17.

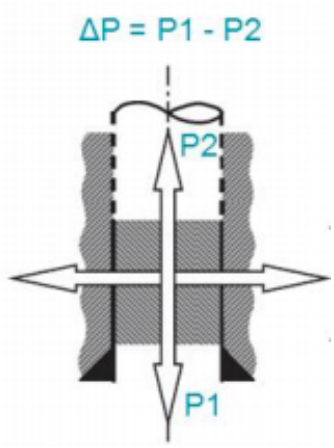


Figure 17: Verification of internal barriers by pressure testing [21].

The acceptable leak rates for pressure testing should be zero unless under specific conditions. NORSOK D-010 [13] establishes that for practical purposes, acceptance criteria should be defined to allow for temperature effects, air entrapment and media compressibility. In addition, the criteria for maximum allowable pressure fluctuation must be established in cases where the leak rate cannot be measured.

Regarding the pressure test, it should be performed in the direction of the flow whenever possible. If this procedure is not possible or considered too risky, then the

pressure test can be performed in the opposite direction of the flow. It is allowed because when barriers are designed to hold pressure from both directions (e.g. cement plugs), they can be considered bidirectional barriers if adequately tested.

Oil & Gas UK [15] also provides instructions related to the verification of internal barriers, especially with regard to cement barriers. The position of the barrier should be verified by tagging or by measurement to confirm the depth of the cement plug.

If the cement plug was set in an open hole, the barrier should be verified by a weight test. When it is set in a cased hole, verification with documented pressure or inflow test is necessary. The procedures are discussed in chapters 6.1.1 and 6.1.3.

According to OGUK [15], an inflow test should be performed considering at least the maximum differential pressure that will be experienced by the barrier after abandonment.

There is an exception presented in OGUK [15] that if a tagged and pressure-tested mechanical plug or previous cement plug is used as a foundation for the barrier in a cased hole, then neither pressure testing nor tagging the barrier is a meaningful procedure. It means that if a cement plug is set as a barrier on a tagged and pressure-tested foundation, then pressure testing or tagging the cement barrier is not required.

6.1.1 Tagging the top of cement and load test

After the plug is installed, testing is required to ensure that the plug was placed at the right depth and provides the expected isolation.

The operation of tagging the top of cement can be done through the employment of a drill pipe, wireline, work string or tool string. The procedure is recommended by API and is a very straightforward operation that enables the exact determination of the TOC. The string is lowered through the well until it lands on the internal well barrier and then a weight reduction is noticed. The top of cement is tagged and its location is confirmed with the benefit that no additional pressure needs to be put on the wellbore.

The load testing method aims to test the barrier's integrity and can be performed combined with the operation of tagging the TOC. The procedure consists of applying a 15,000-lb weight onto the workstring when it is lowered on the TOC. During the test, if the workstring stays steady in position while more weight is being applied then

the test is accepted and the cement plug is approved. On the flip side, if the workstring changes position during the test, then the barrier is considered insufficient or of bad quality.

In some cases, the uppermost part of the cement plug is contaminated due to mixing with other fluids and resulting in a bad cement quality. Hence, it may be necessary to dress off the soft cement to ensure the test will be performed on hard cement. Also, it is important to provide enough time for the cement to set prior to performing the test; otherwise inaccurate results would be provided.

Disadvantages of the load test comprise:

- The concentration of pressure only on cross sections of the working pipe instead of the whole section of the cement barrier
- The corrections for buoyancy and friction factors from the pipe against the casing when using the pipe weight must be taken into consideration [22].

6.1.2 Positive pressure test

The positive pressure test is performed in the opposite direction of flow; hence a differential pressure across the barrier is created with P2 > P1. This test aims to raise the pressure downstream the barrier by pressuring the well up.

Firstly, a low-pressure test should be considered because the barrier has to seal across a range of pressures [23]. It is stated by NORSOK D-010 [13] that a low pressure of 15 to 20 bar should remain stable for at least 5 minutes. If the low-pressure test is successful, then the pressure can be increased to the full test pressure.

The high-pressure test value must be equal to, or exceed the maximum anticipated differential pressure that the barrier will be exposed to. The static pressure test must be monitored for minimum 10 minutes.

Since it may not be feasible to remove all trapped gas, there may be observed an initial pressure change. The system should be recharged to the test pressure and monitored. After minor drops from residual trapped gas, any further pressure drop is concerning and may indicate a failure of the barrier.

Some problems that may occur along the test include temperature effects so it is recommended to allow some time for the temperature to stabilise before a final monitoring of the pressure. It happens because could fluids pumped to a warmer void

may result in pressure increase. And as explained previously, gas should be removed before testing as far as possible to avoid problems during monitoring [23].

6.1.3 Inflow (negative) pressure test

The inflow pressure tests are performed to test the mechanical integrity of the barrier in the direction of flow. The hydrostatic pressure downstream the barrier is reduced (P1 > P2) by displacing the well to an underbalanced fluid or by bleeding off the shut in pressure. Pressure is then monitored to check for leakage, the test is approved if no change is observed in the downhole pressure.

In order to have the inflow test approved, NORSOK D-010 [13] recommends that it should last at least 30 minutes with stable readings. This time should be increased if there are larger volumes, high compressibility fluids or temperature effects.

According to OGUK [23], there are some specific problems that should be considered for the inflow pressure test. It is important to keep in mind that the reservoir pressure acting on the upstream side of the WBE will increase after production has stopped; so if the inflow test is performed immediately after setting the plug, this scenario will not reflect the maximum differential pressure to which the barrier will be exposed to over the years.

6.2 External barrier

The annular or external well barrier must be verified to ensure its vertical and horizontal sealing capability. The evaluation of the external barrier will support the definition of the P&A strategy. NORSOK D-010 [13] states that the casing cement can be considered as a permanent external barrier when there is at least a 30-meter cumulative interval with acceptable bonding verified by logging. And also, this same interval must have formation integrity. If the required length of good quality cement is verified in the annulus, then the casing cement can be considered a permanent external barrier and the internal barrier can be set inside the casing. Thus, a seal across the full cross section of the well will be created.

One of the main issues faced by operators is to determine the quality of the annular seal decades after the primary cement job was set. Loss of cement integrity

can mainly be caused by a poor primary cement job, however it is known that the cement sheath can also fail over the years due to chemical degradation or repeated mechanical or thermal stress. In case leak paths are created across the casing cement, the zonal isolation is lost.

It is essential to gather information about the location of the annular seal, its quality and level of bonding to decide which P&A procedures will be pursued. Logs such as the sonic, cement bond or temperature can verify the TOC in the casing and the integrity of the annular seal. An easier though less effective way to locate the annular seal is by evaluating the record of parameters from the primary cement placement operation. This method is performed with the evaluation of the volumes pumped, volumes returned to surface, annular volume and differential pressure. It is considered an inaccurate method due to uncertainty of the annular volume.

According to the Guidelines for the suspension and abandonment of wells issued by Oil & Gas UK [16], the sealing capability of the casing cement can be assessed with supporting evidence, which may include:

- Logs
- Absence of sustained casing pressure during the well´s life
- The leak off test when the casing shoe was drilled out
- Absence of anomalies during original cementing operations
- Centralization, washouts, lead/tail slurry, annulus pressures and field experience
- Pressure test

If it is not possible to find reliable information or if the available evidences are inconclusive, it is recommended to perform a log or pursue remediation options. If the minimum length of good cement in the annulus is not achieved or if there is no evidence of sealing, there are methods that can be pursued as a solution and the discussions about them can be found in Chapter 9.

6.2.1 Logging tools

The logging tools, used to verify the quality of casing cement, are typically defined as either sonic or ultrasonic tools. The cement bond log and variable density logs (CBL/VDL) are performed using acoustic sonic tools and the interpretation reveals the effectiveness of cementing operations by evaluating casing-to-cement and

cement-to-formation bonds. The major limitation of the conventional CBL tool relates to not identifying possible microannuli and small channels due to variations in cement composition that create density differences in cement [24]. This misinterpretation may lead to serious errors since these channels can compromise the cement seal integrity depending on their extension and connectivity through the annular cement sheath.

As an alternative, combining the CBL with ultrasonic tools provides the most beneficial data and allows all the data to be recorded in one pass of wellbore. The UltraSonic Imager Tool (USIT) provides cement evaluation by ultrasonic principle and detects narrow channels due to its azimuthal resolution that gives a detailed map of material distribution (e.g. solid, liquid, gas and debonded cement). Detecting cement channels and their orientations properly allows squeeze or remedial actions to be undertaken. Since the loggings tools are widely known within the industry, no further discussions about them will be presented on this work.

7. Plugging material alternatives

A proper plugging material must be used in order to safely isolate the wellbore for eternity. Plugging materials used and plug placement techniques define the quality and performance of the P&A operation.

As described in chapter 5.1.2, NORSOK D-010 [13] provides recommendations regarding the characteristics of the plugging material that is used as a permanent WBE. Although Portland cement has been widely used in P&A operations, any suitable material that complies with the specific functional requirements for the well condition can be chosen.

Historically, the cement has been considered the most appropriate material for abandonment purposes. It satisfies the essential criteria of a sufficient plug due to its reliability, durability, low permeability, worldwide availability and reasonable price. Lately, other materials have been developed to minimise some of the concerns related to cement, bring long lasting solutions and ensure that permanent abandoned wells will never leak. This chapter aims to discuss a few alternatives that have been studied over the years.

7.1 Cement

Portland cement is currently used as the prime material for abandonment purposes; it is placed in the well as slurry that hardens under influence of the in-situ temperature and pressure. Cement satisfies the essential criteria of a sufficient plug for being durable, low permeable and relatively inexpensive. Furthermore, it is easy to pump in place, has a reasonable setting time and is capable of tight bonding to the formation and casing.

The main component of Portland cement is clinker, which contains calcareous and argillaceous materials. There are also additives that can be incorporated to improve the rheological properties of cement slurry. For instance, cement set accelerators aim to reduce the setting time and increase the early strength of the plug. Dispersants can be added to lower friction and lower pressure during pumping and elastomers can be incorporated to provide elasticity to the cement and prevent cracking when subjected to high stresses.

The establishment of the slurry design is a decisive procedure and it must comply with a wide range of conditions. The plugging material must keep its sealing capability at a range of different pressures and temperatures and also withstand the corrosive environment and over pressured formation fluids. There are cementing parameters that could affect the sealing and lead to an unsuccessful P&A operation, some of these are: incorrect cement density, poor mud and filter cake removal, premature gelation, excessive fluid loss, high permeable slurry, significant cement shrinkage, cement failure under stress and poor interfacial bonding [25].

It is likely that cement will keep on being the most used plugging material for abandonment purposes due to its many advantages, one of the highlights is the possibility of modifying its properties by incorporating additives.

7.2 ThermaSet

ThermaSet is a plugging material and a cement alternative product that was designed to overcome a lot of the traditional cement issues. It is described as a particle free polymer-based resin produced by Wellcem AS. Figure 18 presents the product in liquid state. ThermaSet is pumped down in liquid state and transformed into a solid by a temperature-activated process. The initiation of curing process, which refers to the hardening of the polymer material, is triggered by downhole temperature. Then the curing time can be designed to fit the predetermined temperatures of the area where the plug will be set. The operating temperatures can vary from -9 ^{o}C to 150 ^{o}C. The viscosity and density of the material can be adjusted over a wide range by adding different fillers. Viscosity can vary from 10 to 2MM cP while the density range is 0.7 to 2.5 S.G [26].

While the cement has its setting time based on a hydration process that starts when cement powder is mixed with water, ThermaSet is thermally activated. The fact that the curing temperature and time can be predetermined is a great advantage over cement. The risk of an early set completely vanishes by setting the curing temperature to the downhole temperature. Moreover, the curing time can be regulated from a few minutes to several hours and wait on cement time can be eliminated. Another advantageous properties are that ThermaSet does not shrink as it sets, is compatible

with most fluids and cements and also can tolerate up to 50% contamination as it still maintains its sealing capability.

Since it is possible to produce ThermaSet with a wide range of densities and viscosities, the product can be designed to be easily pumpable and placed in the wellbore with precision. Due to the fact that it is a particle free fluid, it can also penetrate deeply into formations and annuli to seal off micro cracks and narrow channels. Additionally, there is no need for extra wellsite equipment because it can be pumped downhole using conventional cementing techniques and equipment.

Figure 18: ThermaSet plugging material [19].

Apart from all the advantages previously discussed in this chapter, the main benefit of Thermaset when compared to Portland cement may be its superior mechanical properties. On the other hand, it is important to investigate how these tests were performed and what was the setting time used for the cement prior to testing its properties. Table 3 presents a comparison of mechanical properties between ThermaSet and Portland cement, it states that ThermaSet has a higher compressive, flexural and tensile strength. The lower Young`s modulus shows better elasticity which makes ThermaSet ductile while cement is not.

Table 3: Properties of ThermaSet and traditional cement [27].

Properties/Material	ThermaSet	Traditional Cement
Compressive strength (MPa)	77	58
Flexural strength (MPa)	43	10
E-modulus (MPa)	2240	3700
Tensile Strength (MPa)	60	1

Property wise ThermaSet may be an obvious choice, however there are concerns related to using it as a plugging material. The most prominent ones are high cost and little experience, however price may be justified by less setting time. It is also important to verify the long-term capability of this material. One of the greatest challenges that service companies face when introducing a new technology in the industry is the reluctance to try something new. The P&A industry already comprises high-risk activities and is reasonable that a more traditional material is preferred for being widely known, used and tested.

ThermaSet is being thoroughly tested to have its properties verified. SINTEF, which is the largest independent research organisation in Scandinavia, has performed long term integrity tests with ThermaSet and the results were highly satisfactory. After the material sets, it can handle pressures and temperatures up to 320 ^{o}C and 500 bar respectively and is also corrosion resistant.

7.3 Sandaband

Sandaband, also named sand for abandonment, is an alternative to cement plugs developed by Sandaband AS. The company defines sandaband as a flexible, non-shrinking and thermodynamically stable plugging material that ensures an ever-lasting seal in both open and cased holes.

Sandaband is a Bingham-plastic unconsolidated plugging material with high solids concentration that ranges from 70-80%. The solids composition is basically of quartz, crushed rock and micro silica while the remaining 20-30% volume is water. Also a small amount of additives such as dispersant and viscosifier are added to keep the product pumpable. Quartz is one of the hardest and most thermodynamically stable mineral available, it does not degrade over time and is not affected by downhole fluids (e.g. carbon dioxide, hydrogen sulfide and hydrocarbons). The particles are kept together by electrostatic forces between the water molecule and the surface of the smallest micro silica grains and hinder flow in the pore space [28].

As mentioned above, the product has the rheological properties of a Bingham plastic. Bingham plastic fluids are described by the fact that they need a certain shear stress (yield point) to start behaving as a liquid as seen in Figure 19. They act as a solid until the applied pressure is high enough to break the shear stress and hence making the fluid to flow. Above the yield point, the shear rate is linear with the shear

stress, similarly to a Newtonian fluid. Figure compares the behaviour of both Bingham plastic material and Newtonian liquid.

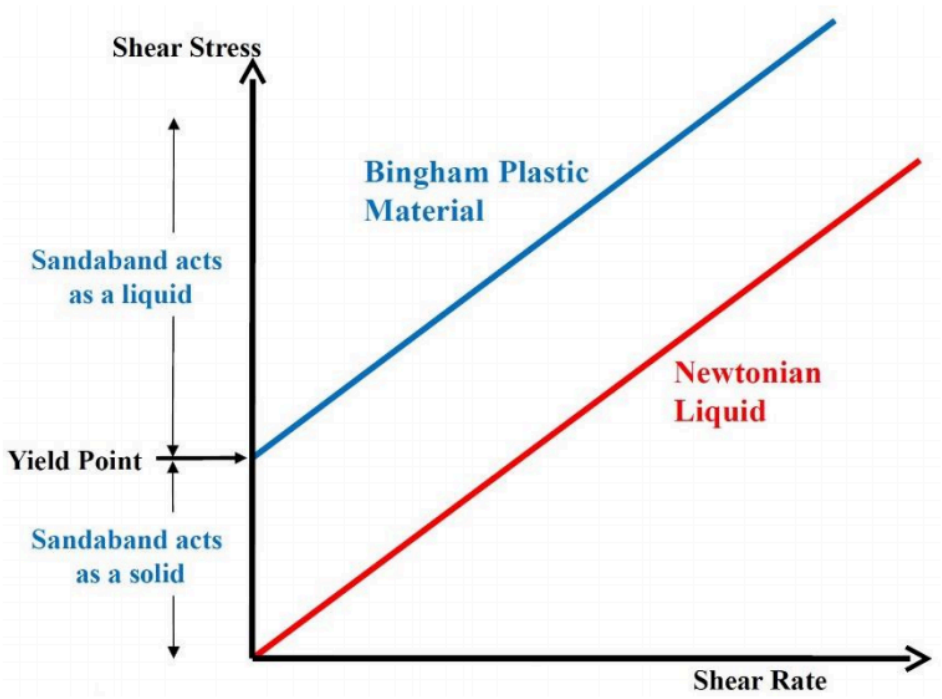


Figure 19: Bingham plastic material [29].

Thus, during pumping the material is exposed to high shear stress and then acts as a liquid. Soon as the pumping stops and the shear stress is removed, the slurry rapidly forms a rigid body. Since no chemical reaction is involved, there is no shrinkage and setting time is not time-dependent. When the material is exposed to dynamic loads and stressed beyond its strength, it will simply deform and reshape as represented in Figure 20, whilst a brittle material (e.g. cement) would eventually crack and fracture. Therefore, concerns regarding leakage through fractured channels or microannuli are avoided.

Figure 20: Sandaband and its Bingham plastic properties [29].

Although the product has several advantageous properties, there are also some disadvantages associated with it. Sandaband is more expensive when compared to cement, has to be premixed onshore and needs extra wellsite equipment. Furthermore, the product requires a solid foundation to support its placement and position; otherwise it would fall through due to density difference. As opposed to other plugging materials, this foundation has to be permanent; hence it cannot be a mechanical plug because is not accepted as a permanent barrier, then it can only be provided by other permanent sealing materials or the well floor.

Det Norske Oljeselskap used sandaband to permanently plug and abandon the exploration well 25/8-17 located on the Norwegian Continental Shelf of the North Sea. In this case, it was used to set a 300-meter plug from total depth to above reservoir. The operation was successful and about one day of rig time was saved mainly due to no time waiting for cement to settle. Even though Sandaband is more expensive than cement, the saving in rig time was sufficient for Sandaband to pay for itself [30].

7.4 Shale as annular barrier

It has been acknowledged that certain formations (e.g. shale or salt) have a natural tendency to move radially inward as a result of stress differences. Although this phenomenon is undesirable during drilling and casing running, it may be advantageous for P&A operations when shale formations create an annular barrier behind an un-cemented casing [28]. NORSOK D-010 Rev.4 [13] includes that shale, as a bonded and impermeable in-situ formation, is accepted as an annular well barrier element if it is in compliance with the WBE requirements. The P&A operations of Brazil's pre-salt will also experience this same advantage since salt formations can also be accepted as an annular barrier.

NORSOK D-010 [13] and Oil and Gas UK Guidelines [16] present the requirements that must be fulfilled to consider shale a permanent sealing formation. In order to provide an annular barrier, the displaced formation must have certain physical properties as sufficient rock strength to withstand the anticipated future pressures and extremely low permeability to fluids. Also, the displacement mechanism of the shale must be assessed to verify if it is suitable to preserve the well barrier properties. The barrier must seal over the full circumference of the casing and over a sufficient interval along the well. While NORSOK D-010 Rev.4 [13] states that the minimum length of the barrier must be 50 meters MD with good continuous bonding, the Guidelines for the Abandonment of Wells (issued by Oil and Gas UK in 2015) [16] requires a minimum length of 100 feet. The position, length and sealing capability of the shale formation must be verified by two independent logging tools, for instance CBL and USIT as discussed in chapter 6.2.

Similarly to all other annular barriers, the minimum formation stress at the base of this element must be sufficient to withstand the maximum pressure that could be applied, and the entire element must be suitable to withstand the maximum differential pressure. This confirmation is done by pressure testing the barrier; the tests are usually performed as leak-off tests (LOT) to avoid that a possible leakage is missed when applying lower pressures. NORSOK D-010 [13] states that the formation integrity must be verified by a LOT at the base of the interval. One way of performing it is by perforating the casing at the base of the barrier, then apply pressure until either a pressure response is observed at the annulus casing at the surface or a leak-off pressure is seen [31].

If the collapsed formation can be verified as an annular barrier, both P&A operational time and expenses could be saved. In 2016, more than 100 wells were already plugged and abandoned by Statoil using this method [19].

8. Plug and abandonment operational procedure

Describing a procedure for P&A operation is a not a straightforward task, it is challenging to make a standardised approach because a variety of uncertainties and factors need to be individually assessed for each well scenario.

Each well is designed to fit its purpose. As mentioned in chapter 1, exploration wells, appraisal wells, production wells and injection wells are all constructed throughout the steps of an oil and gas field`s life. A key aspect to define a P&A procedure is to have reliable data about the drilling phase, well completion and design, interventions performed, well performance and reservoir condition over the life of the well.

8.1 Required information for the design basis

Firstly, it is necessary to understand the current status of the well assessing the quality of the data available. Therefore, recordkeeping and data gathering are pivotal throughout the well's life cycle. This can be a challenge in fields that were operated by different companies, especially regarding temporarily abandoned wells and old wells whose information was lost over the years.

The design of the P&A operation and how it will be conducted is highly dependent on many parameters to ensure the operation will be pursued properly. NORSOK D-010 [13] recommends that the following information should be gathered as a basis for the well barrier design and abandonment programme:

I. Well configuration (original and present) including the depths and specification of permeable formations that are source of inflow, casing strings, status of cement behind casing, wellbores, sidetracks, etc.
II. Stratigraphic sequence of each wellbore showing reservoirs and information about their current and future production potential, including reservoir fluids and pressures (initial, current and in an eternal perspective).
III. Logs and data from cementing operations.
IV. Formations with suitable well barrier element properties (e.g. strength, impermeability, absence of fractures and faulting)

V. Specific well conditions such as scale build up, casing wear, collapsed casing, fill, H_2S, CO_2, hydrates, benzene or similar issues.

8.2 Phases of permanent well abandonment

A general sequence of three phases was defined for permanent well abandonment activities [16]:

- Phase 1: Reservoir abandonment
- Phase 2: Intermediate abandonment
- Phase 3: Wellhead and conductor removal

8.2.1 Reservoir abandonment

The first phase is the reservoir abandonment; notice that at this point no barrier has been set against the reservoir yet so full well control is required. It is defined as the moment when primary and secondary permanent barriers are set to isolate all reservoir producing or injection zones.

The activities may vary whether it is referred to an open hole or cased hole perforated section. In case it is a cased hole, the main challenge occurs when it is needed to re-establish annular barriers as a result of poor cement jobs behind the casing, this topic will be further discussed in Chapter 9.

The production tubing may be left in place, partially or fully retrieved. The reservoir abandonment phase is complete when the reservoir is fully isolated from the wellbore.

8.2.2 Intermediate abandonment

The intermediate abandonment aims to isolate the intermediate permeable zones with a flow potential, isolating them from each other and avoiding communication within the wellbore. In case it was not done in the first phase, the second phase consists of pulling the upper completion (i.e. production tubing above production packer) in order to evaluate the annular barriers. In case it is concluded that the sealing capacity of the annular barrier is not adequate, remediation methods must be conducted. The last step of the second phase is to set an open hole to surface barrier to

completely isolate the well. The phase is complete when no further permanent barriers are required.

8.2.3 Wellhead and conductor removal

When it is required by regulations, the third phase of the P&A operation consists of cutting and removing the casing strings and retrieving the wellhead.

The Resolution No. 46/2016 [14] issued by ANP does not require that the wellhead and conductors must be removed for permanent P&A; it only states that a surface plug must be set in case the wellhead, casings or conductors are removed. The Resolution No. 46/2016 [14] is the latest update of the former Resolution No. 25/2002, which used to state that a surface plug must be implemented with at least 30-meter height and it must be placed between 100 to 250 meters below the seabed.

The Guidelines for the Abandonment of Wells issued by Oil & Gas UK in 2015 [16] recommends that is a good practice to retrieve all casing strings to a minimum of 10 feet (3 meters) below the seabed in order to accommodate fishing activities in the area after P&A. The newest revision of NORSOK D-010 from 2013 [13] does not include requirements regarding the cutting depth. Additionally, it states that for deepwater wells, it may be acceptable to leave or cover the wellhead structure.

Traditionally, the most common method used in phase 3 is the cutting knives; they cut one casing at a time and subsequently put it out of the hole. Explosives have also been used as a method even though they are less controllable and introduce risks for Health, Safety and Environment (HSE). Both methods need a rig in order to be pursued.

Alternatively, a new technology was developed lately using abrasive water jet cutting technology to cut the conductor and all the following casing strings in one run. This system is very effective as it cuts through multiple strings simultaneously, presents much less HSE risks and can be a rigless method. The fact that the system can be deployed from riserless light well intervention vessels is highly beneficial since rig time costs can be avoided by using dedicated vessels.

The well is considered fully abandoned after the end of phase 3 by having the wellhead and conductor removed. After this, the well will never be used or re-entered again.

8.3 General steps of the operational procedure

Each P&A procedure is unique since each well has its own distinctiveness. However, it is possible to provide general steps that are shared between most of the P&A operational procedures.

8.3.1 Data gathering & planning

The first step for establishing a P&A programme is to assess all the data available and understand the status of the well. The required information for the design basis was discussed in chapter 8.1.

After data gathering, the P&A program will be designed based on well status and reservoir conditions. All procedure must be in compliance with regional requirements and international guidelines.

For the planning phase, it is important to define a convenient approach. It is a common practice embraced by the oil and gas industry to split the P&A operation in different campaigns when there are several wells involved. The operation can be optimised by performing work on one well and then moving to the next to perform a similar activity. Therefore, it is possible to reduce the time spent on mobilisation and demobilisation activities.

8.3.2 Verify the surface equipment integrity

It is required to assess the wellbore conditions and test the surface equipment integrity prior to any activities that may take place during the P&A operation. This is decisive because the valves on the Christmas tree and the wellhead seals will act as WBE during well intervention. Hence, must be tested for integrity and functionality.

8.3.3 Prepare the well

A wireline equipment is then used to check the wellbore conditions, if there are any obstructions, to confirm the tubing inside diameter and also to pull the downhole safety valve (DHSV).

The DHSV is a safety device installed in the upper wellbore to provide an emergency shutdown when necessary. There are two types of subsurface safety valves (SSSV) available, one is surface-controlled and the other is subsurface-controlled.

Both of them are designed to be fail-safe which means that the wellbore will be isolated in case there is any system failure or damage to the surface control facilities.

The wellbore is inspected using a slickline unit that consists of a hydraulically controlled spool of wire used to place and retrieve tools and flow-control equipment downhole. In case obstructions or other issues are found, more preparation will be needed. Information acquired in this phase will be also used for planning the P&A procedure.

8.3.3 Kill the well

The well must be killed before it is ready for the P&A operation. The aim of this phase is to achieve hydrostatic overbalance in the well in order to prevent any flow of reservoir fluids. Well killing is carried out by replacing the fluid in the wellbore with a column of heavier fluid. Hence, the hydrostatic head of the column will overcome the inflow pressure in the wellbore and the well will be overbalanced.

The well kill operation can be performed using several methods; the most common ones are reverse circulation and bullheading.

In the reverse circulation, a kill fluid is pumped down the annulus and up through the tubing just above the production packer using a communication point. The kill fluid will then displace the lighter wellbore fluids increasing the hydrostatic pressure.

The bullhead operation is performed with kill fluid being pumped into the well against pressure in order to compress the fluid in the tubing and force the wellbore contents back into the reservoir formation. Pumping of kill fluid will continue until the tubing is left with only kill fluid. Hence, this high-density fluid will maintain a stable overpressure once pumping is complete.

8.3.4 Check the annuli pressure

This step aims to verify if there is any pressure build up in the annulus before the tubing is cut and pulled. The annular pressure build up is the pressure generated within an annulus by thermal expansion of trapped annular fluids when exposed to high temperatures by hydrocarbons producing [32].

The occurrence of annulus pressure buildup depends on two conditions: the sealed annuli and temperature increase which triggers the pressure increase. The

sealed annuli are usually associated with a poor cement bond during drilling phase while the temperature factor is associated with the production phase when the trapped fluid will be heated by the heat exchange from the production fluid. The temperature increase will then trigger the increase of annuli pressure.

It is a very relevant concern especially in subsea wells because the annuli between outer casing strings are usually not accessible and bleeding off the increase annuli pressure may not be possible.

In this phase, the pressure is bleed off the annuli and monitored to check whether it rebuilds again. This kind of pressure buildup is also known as sustained casing pressure and may cause integrity issues while removing the tubing.

8.3.5 Cut the tubing

The Guidelines for the abandonment of wells issued by Oil & Gas UK in 2015 [16] allow the operators to leave well completion tubulars (e.g. production tubing) in hole as long as permanent barriers are set through and around them. However, it is also stated that cables and control lines should not form part of permanent WBE. According to NORSOK D-010 [13] and Brazilian regulation [14], control lines and downhole equipment can cause loss of integrity by creating potential peak paths and that is why they cannot be considered part of a permanent well barrier.

When the cables are clamped to the tubing as showed in Figure 21, currently there is no technology able to remove the control lines without pulling the tubing. As a consequence, the conventional method implemented is to cut and pull the tubing.

Figure 21: Control lines externally clamped to the production tubing [33].

Another reason why the tubing needs to be cut and pulled out of the hole is because current technologies are unable to verify cement quality through multiple

casings. Then the tubing is retrieved in order to log the cement bond behind the production casing and evaluate its quality. The tubing is usually cut a few meters above the production packer and below the downhole gauge.

8.3.6 Nipple down the vertical Christmas tree

The P&A operations performed are slightly different when the well is equipped with a vertical Christmas tree (VXT) or a horizontal Christmas tree (HXT). In VXT systems, the tubing hanger is typically installed inside the wellhead and the tree on top of the wellhead, while in HXT systems the tree is installed on the wellhead and then the tubing hanger is installed inside the tree instead of the wellhead. In both cases the tubing hanger forms a connection between the production tubing and the tree.

Back to drilling and completion phases, a VXT can only be installed onto the wellhead after all drilling and casing activities are complete and the tubing hanger run and locked into the wellhead. Therefore, when it comes to P&A operations, the VXT must be retrieved and BOP installed before pulling the tubing. To sum up, the VXT can be recovered without having to recover the downhole completion.

On the other hand, the HXT is designed to interface with the BOP. Back to completion phase, the BOP is retrieved to the surface prior to progressing with the completion, then the HXT is installed onto the wellhead and the BOP is run once again but now locked onto the top of the HXT. After this, the downhole completion and tubing hanger are run and internal tree cap is installed. Regarding the P&A operations, the HXT is retrieved after the tubing is pulled and after deep and shallow plugs are set.

Assuming that the P&A operation is performed in a well equipped with a VXT, the tubing is cut and then the VXT is removed to accommodate the BOP. The VXT is nippled down, the BOP is nippled up and the operation to pull the tubing can be performed.

8.3.7 Retrieve the annular safety valves

The annular safety valves (ASV) are usually installed in gas lift completions to prevent uncontrolled flow in the A-annulus when actuated.

The ASV can be either wireline retrievable or tubing retrievable. In the first case, they can retrieved in a rigless operation during the offline work. On the other hand, when they are an integral part of the tubing they must be retrieved simultaneously while pulling the tubing [19].

8.3.8 Pull the tubing

As described in chapter 8.3.5, the production tubing is retrieved when it is needed to log the production casing cement and when the control lines are clamped to the tubing. This is considered a heavy lift operation and requires a rig.

8.3.9 Diagnostic logging run

After the tubing is pulled out of the hole, the production casing is revealed and logging tools are run. As already discussed in chapter 6.2.1, sonic and ultrasonic logging tools such as CBL and USIT are used to assess the downhole conditions.

The logging operation is performed to assess the quality of the barrier element behind the casing and the length of the annular seal. This is an important phase of the operation because the information acquired now will be the basis of the P&A approach that will be established. The interpretation will enable decisions to be made whether the external barriers are considered sufficient or if remediation methods should be pursued.

8.3.10 Set the permanent barriers

All the data gathered until now will support the activities implemented in this phase. At this point, the required information listed in chapter 8.1 was evaluated and the P&A approach was chosen.

In some cases, it is desired to plug the perforations within the reservoir formation due to different reasons. This can be done to isolate the wellbore from the water of a depleted reservoir with strong aquifer support. Or even to avoid that injection water enters the wellbore from injection wells designed to provide pressure support to that reservoir. The perforations are usually plugged to isolate the wellbore from undesirable fluids; this is conducted by squeezing cement into the perforations after the well is killed [19].

When the perforations do not need to be plugged, then a mechanical device (e.g. bridge plug) can be set above the perforations. The mechanical plugs are used as a foundation for the upcoming cement plug to prevent slumping and also as a method to reduce contamination on the bottom of the cement plug.

As already discussed in chapters 8.2.1 and 8.2.2, first the reservoir must be plugged with two permanent barriers and then the intermediate zones are plugged. It may be necessary to pull the production casing in order to log behind the intermediate casing and check the quality of the annular seal. It may also be required to pull the intermediate casing to establish a full cross section barrier in the surface casing.

By the end of this stage, a surface plug may be set according to the requirements of the Brazilian regulation that were already discussed in chapter 8.2.3.

8.3.11 Cut & retrieve the upper parts of the well

The last stage of the P&A operational procedure is to remove the upper parts of the well in case it is required by local regulation as discussed in chapter 8.2.3. This is done in two steps. The first is to cut and retrieve the upper parts of the conductor and following casing strings. The second is to retrieve the wellhead.

Although this stage is traditionally performed using a rig, lately became possible to perform it in a rigless operation using vessels.

8.4 Brent field operational procedure

The procedure used for suspension and decommissioning of Brent field wells was developed by Shell United Kingdom [11] and comprises a sequence of operations.

According to the decommissioning programme, the first step is to isolate the reservoir by setting a temporary mechanical plug made of metal and rubber, then the existing hydrocarbon fluids are replaced by a kill weight fluid. A second mechanical plug is then set at a shallower depth in order to allow the Christmas tree to be retrieved and replaced by the BOP. Following the retrieval of the shallower plug, the operations will continue using the main rig.

Completion tubing is retrieved allowing the well to be logged to assess the quality of cement bond behind the production casing. Next step is to implement the

reservoir abandonment barrier cement plug. If the casing cement is an insufficient barrier, then the original cement bond will be remediated using P&A techniques. In case it was verified the quality of the cement bond, then a cased hole cement plug will be set.

An environmental plug must be set above the other barriers when it is necessary to ensure that oil based muds are isolated from the environment.

After the period of final well monitoring, the wellhead and remaining conductor and casing strings are cut and recovered leading to the end of the operations.

9. Plug and abandonment techniques

There are traditional and new technologies that were developed over the years to be used in P&A operations as a solution to the lack of annular seal in external barriers. As already discussed previously and presented again in Figure 22, a requirement for a permanent well barrier is that it must include all annuli, extending to the full cross section of the well and seal both vertically and horizontally.

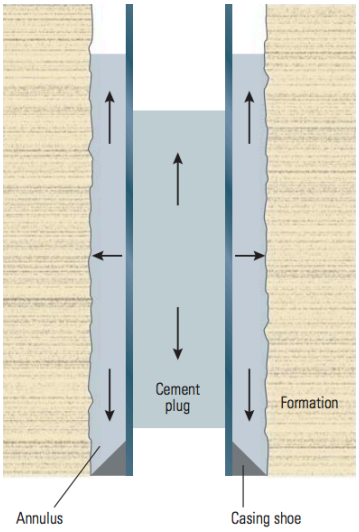


Figure 22: Casing cement and cement plug as a permanent barrier [34].

When placing an internal barrier at the required depth in the well, it must be placed where there is a verified external barrier so it could provide the required isolation. When casing cement aims to function as an annular seal, the quality of the cement bond and the length of the verified good cement are assessed to check if they are in compliance with the requirements. However, the interpretation from logs may determine that the primary cement job has limited sealing capability and is considered insufficient to provide a permanent barrier due to the quality and quantity of cement in the annulus.

If the annulus seal is found ineffective, then it must be remediated as part of the P&A procedure by, for instance: cutting and retrieving the casing; placing cement in the annulus by suitable means such as perforating or circulating; or by section milling [16]. The selection of the technique should take into account its reliability and that is why P&A techniques were developed and are still being improved to provide a proper

annular seal. The remedial cementing technique will not be covered in this work due to its low reliability and low success ratio.

9.1 Cut & Pull

In case the annulus contains no cement, then the cut and pull method can be applied. In general, the conductor and surface casings are cemented all the way to surface while the TOC of the intermediate and production casing varies since different formation zones need different lengths to be cemented.

To perform the cut & pull method, typically is found a free point where there is a lack of cement in the annulus. Then, the casing string is cut above the free point and pulled out of the hole. The free point can be found by cement logs or stretch tests similar to those used to find the free point of a stuck drill pipe. The stretch test is performed using a wireline tool with a free-point indicator that operates by detecting stretch in the tubular when tension is applied to the surface.

Typically, multiple trips are necessary to cut and pull each casing string. Hence, it leads to more trips in and out of the hole increasing the overall time of the P&A activity. If it is not possible to pull the string at the first attempt, then a new cut must be made and the pulling process is repeated.

9.2 Section milling

Traditionally, section milling has been the most used method among the P&A techniques available, it is chosen when the casing strings cannot be cut and pulled. The method aims to grind away a section of the casing along with the contamination behind it to create a section of fresh formation where a proper permanent barrier can be placed. The contingencies and challenges faced by section milling operation will be discussed in this chapter.

NORSOK D-010 Rev.4 [13] developed a manual to be applied when section milling is required. The decision tree, available in Appendix B, aims to provide guidance on the steps that must be followed to plan the section milling operation from logging the casing cement to establishing the barriers. However, this topic will not be further discussed on this work.

9.2.1 The operation

The casing section is milled away with a tool called section mill. In the operation, a rotary tool assembly is lowered to the desired depth of the section milling. The tool is run on a mix of normal drill pipes and drill collars to add weight to the device. A nozzle threaded in the bottom end of the tool allows positive fluid control, keeping the cutting structure cool and creating a continuous flushing-and-cleaning action on the section milling knives.

The milling tool is made of several knives on pivots that are rotated out of the tool body with a hydraulically activated cone. Once the device arrives at the required depth, the cone that is powered by circulation pressure exerts the force required to extend the cutting knives. Once the knives are through the casing wall, they are locked out in this extended position then a cut is made by applying rotational force [35]. After that, weight is applied to push the mill down and break away the casing string of the interval length.

After the section of the casing is milled or when the knives are worn out, milling fluids circulate until the hole is clean. Section milling fluids must be able to keep the open hole stable, cool the device and transport swarf and debris to the surface. The section is then under-reamed to enlarge the wellbore past its original drilled size and expose fresh formation in order to achieve a good bonding when the permanent barrier is set. The reamer also removes all cement, filter cake or other contaminants [36].

The conventional section milling operation requires at least two dedicated trips, one trip to section mill the desired zone and the other trip to under-ream the hole as seen in Figure 26. This is necessary because the conventional two-trip system uses two different bottomhole assemblies (BHA), one section mill BHA and one reamer BHA as shown in Figure 23.

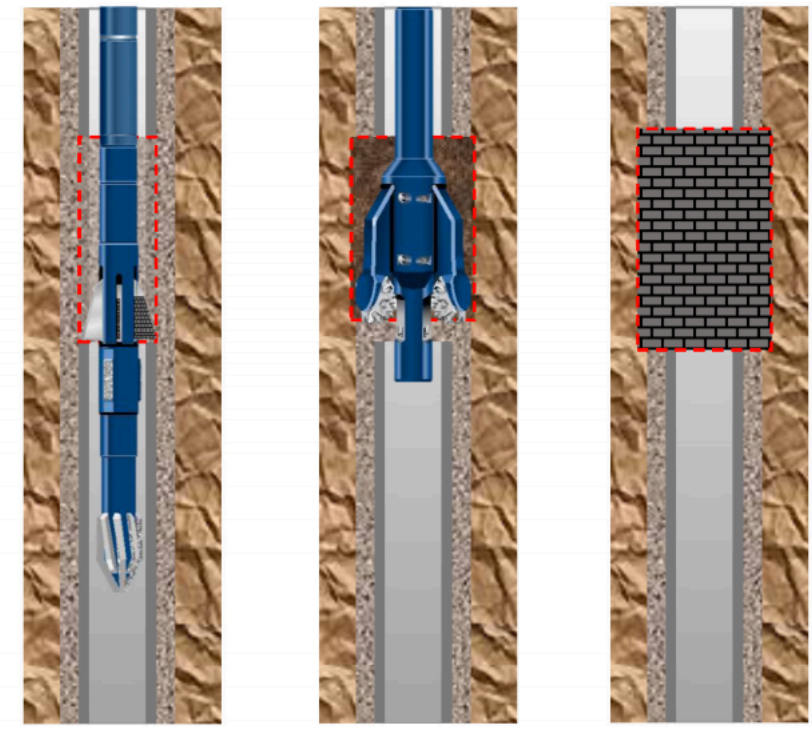


Figure 23: Conventional section milling operation [36].

A new design was recently developed in which the under-reamer and the section mill are deployed on the same BHA. Hence, the tool is able to remove casing from the wellbore and under-ream to virgin formation in just one trip. Figure 24 compares the conventional two-trip system with the new single-trip system. With the single-trip BHA, once the fluid rheology is confirmed for good wellbore cleaning, the section mill initiates the milling operation. After the required casing window length is properly milled, then the under-reamer is positioned at the top of the window and then activated to clean out the wellbore beyond its original drilling hole size to expose fresh formation.

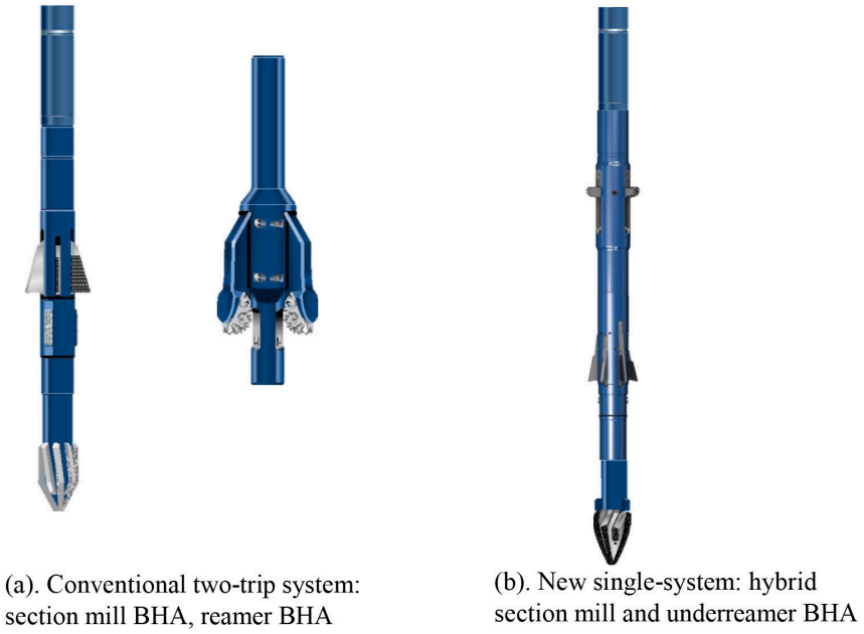


Figure 24: Conventional two-trip system on the left and new single-trip system on the right [36].

The ProMILL system developed by Schlumberger is an integrated solution that combines a bridge plug assembly, a section mill and a high-ratio under-reamer. Hence, the equipment is able to perform all these operations in a single run.

9.2.2 Cutting material

Tungsten carbide is the finest hard facing material available today for downhole steel cutting and milling tools. Its properties give the cutting material a significantly increased tensile strength and enhance performance [37].

Initially, the cutting structure was made of randomly crushed sintered tungsten particles as seen in Figure 25. Carbide cutting material with the randomly shaped pattern used to be the main building blocks of the cutters.

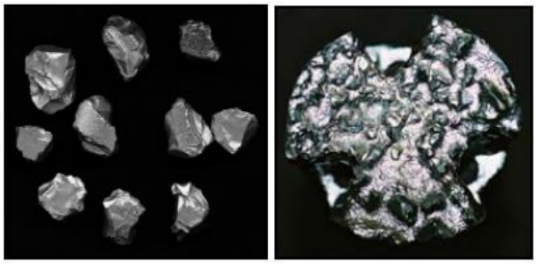


Figure 25: Randomly crushed, sintered tungsten particles used for milling tools [37].

Then the industry introduced the carbide inserts into the cutting matrix as seen in Figure 26. The application of the insert highly increased the penetration rates and mill life. The jobs that were previously performed by the randomly crushed sintered cutting material were enhanced by the shaped carbide technology.

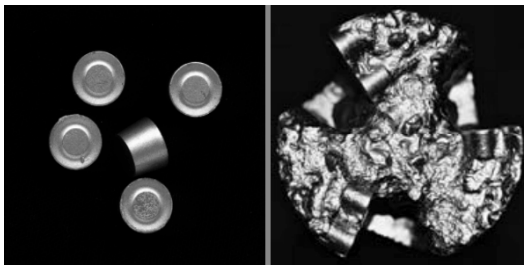


Figure 26: Carbide inserts used for milling tools [37].

In 2000 another type of cutting material was introduced and it was made of powder carbide. Each individual cutter has an identical geometry optimised in order to always provide a sharp cutting edge no matter how the insert is placed. It has a total of 16 cutting points and 8 cutting edges. Figure 27 presents this new cutting material.

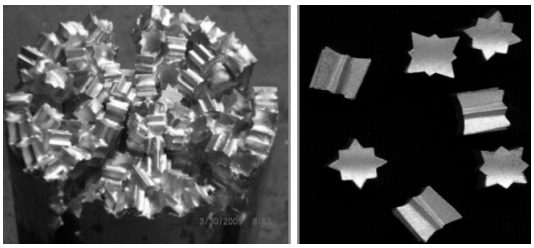


Figure 27: Shaped power cutters with increased surface area [37].

After all these different shapes of cutters were developed, they had their performance evaluated and many recipes were tested in the lab. All this research eventually lead to the optimum set of materials that would deliver a much higher level of impact resistance. Figure 28 shows this most recent design that was introduced in 2009 and is called the P-cutter.

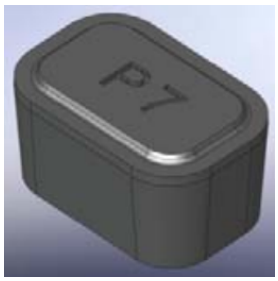


Figure 28: P-cutter and its latest technology for section milling operations [37].

Due to its longer cutting edge, the P-cutter is not susceptible to single point loading which is commonly seen on round shaped cutters. The longer edge distributes the load more evenly on the cutter giving it a longer life. An additional feature was incorporated into the design, it is called chip breaker and delivers smaller cuttings that are easier to circulate back to the surface, reducing the risk of forming pack-offs during the section milling operations. Pack-off is defined as plugging the wellbore around the drill string or BHA [37].

From 2008 to 2010, ConocoPhillips completed P&A campaigns at the 2/4 W Platform in the Norwegian Sector of the North Sea. During the campaigns, section-milling blades were dressed with traditional carbide inserts (Figure 29) and also with the new P-cutters (Figure 30). In order to deliver a 165-foot window, the section milling blades with traditional inserts took around 4 runs while the P-cutters could deliver the entire window in a single run.

Figure 29: Section milling blade dressed with traditional cutters [37].

Figure 30: Section milling blade dressed with P-cutters [37].

9.2.3 Challenges

The section milling operation can be difficult to execute efficiently and some of the challenges associated with the method are discussed below.

9.2.3.1 Time spent & uncertainties

The complexity of the operation along with unforeseen and challenging incidents can cause the operation to take more time than expected. The lack of data on

oldest wells has been a challenge and decisions have been made without proper knowledge. The tripping time is also pivotal to increase the duration of the procedure. The whole P&A operation including all of its phases can take from 30 to 60 days to be complete however it is difficult to forecast this duration due to the contingencies that may come up.

9.2.3.2 Swarf generation & handling

Another issue faced when performing section-milling operations is the swarf generation and transport. Swarf describes the cuttings or metal shavings generated by milling the casing that needs to be circulated out of the hole. Obviously, the weight of generated swarf depends on many conditions such as the weight per unit length, casing window, wall thickness and the incidence of corrosion and erosion [38].

In order to perform a successful operation, it is pivotal to clean the wellbore properly and transport the swarf generated until the surface. Otherwise, bird nests may occur where there is a build-up of entangled steel slices stuck in the well. As discussed in chapter 9.2.2, the cutter technology has been improved over the years to reduce the length of the cuttings into smaller pieces and then ease transportation.

The problems occur because not all swarf and skimmed casing remnants can be cleared from the wellbore. When the swarf is not properly removed, it may jam around the drill string or BHA causing a sudden reduction or loss of the ability to circulate and also an increase of the pump pressure. Even swarf and other debris that are successfully transported may accumulate as it moves upward where there is a reduced annular velocity, for instance in BOP cavities. Pack-off is considered a severe issue that may happen during the operation and must be avoided.

The swarf handling operation on topsides also needs to be planned especially when the rig does not include the equipment necessary to separate swarf from the milling fluid. For instance, during Shell`s Brent field campaigns, the milling performance was restricted by surface swarf handling capacity as discussed in chapter 9.2.4. There are also HSE risks when handling the sharp metal cuttings; hence the offshore crew must wear appropriate protective equipment.

9.2.3.3 Damaging BOP

It is considered a serious integrity concern when the swarf accumulates in BOP cavities. The most critical areas are in the ram seals and the annular seal inside the BOP. Since the BOP is the final barrier against a blowout, it needs to be carefully monitored. In order to get access to the cavities, the BOP must be retrieved to the surface, dismantled, inspected and cleaned to remove residual swarf. It requires a heavy lift operation and additional time consumption leading to more expenses.

9.2.3.4 Open hole exposure & milling fluid

The fluids that are used in section milling must have sufficient weight to keep the open hole stable and sufficient viscosity to suspend and transport swarf and other debris to the surface. It is pivotal to evaluate the fluid rheology and flow patterns.

When the milling fluid profile is designed, it must take into consideration that an open hole with direct contact to the formation is exposed after a section of the casing string and annulus cement is milled. Therefore, the milling fluid properties must be designed to be close to the average of the fracture pressure and the pore pressure to keep the open hole stable. The milling fluid requires high density and viscosity to be able to lift and transport the swarf and other debris to the surface; this can create equivalent circulating densities (ECD) that exceed the fracture gradient of the exposed open hole and leading to losses while circulating, swabbing, well control problems, poor hole cleaning and packing off of the BHA [39].

Prior to designing the milling fluid, it is important to evaluate the type of mud that was used during the primary drilling of the well. This step is necessary because settled mud behind the casing could affect milling fluid properties. Typically, water based mud (WBM) is used for milling fluids then it is pivotal to design the mud in a way that its properties will not change if it is mixed, for instance, with contaminants from oil based mud (OBM).

9.2.3.5 Wear of the mill

Worn out cutters are a very typical problem faced during section milling operations. When the cutters become worn out they must be exchanged with new cutters to maintain efficiency, so the BHA must be retrieved to the surface to change the mill, which will increase the duration of the operation. As discussed in chapter 9.2.2, technology has developed new designs and recipes to manufacture the knives and provide better performance.

9.2.3.6 Plug verification

There are two ways of verifying the permanent well barrier when it is placed in a milled section, the operator can either decide to leave the TOC inside the cased hole above the milled window or leave the TOC in the hole.

Regarding the first option when the TOC is left inside the casing, then the TOC must be verified by tagging, weight testing and pressure testing. However, these tests will only assess the quality of the cement inside the casing.

If the TOC is set inside the open hole section, then it is almost impossible to verify the plug by a true pressure test. A pressure test is not performed due to the risk of fracturing the formation that is left open between the plug and the casing. Although a tag can be used to verify the setting depth, the sealing ability cannot be verified.

To sum up, it is very difficult to assess the sealing capability of the plug in both cases.

9.2.3.7 Vibrations

The section milling operation has an aggressive approach when it comes to the vibrations that occur and the effect they have on equipment. The device develops a high level of axial and torsional vibrations while the cutters grind away the casing string.

The rig must be stable throughout the operation since small and rapid movements of the rig during cutting can be transferred to the section mill causing it to take cuts of different and irregular depths. The vibrations will then exacerbate the

irregularity of the cuttings; as a result, there will be a reduction of the ROP and a damaged BHA.

Recently, technology has improved to tackle the challenge of vibrations. During ConocoPhillips's Whiskey campaign in 2009, a new downhole optimisation sub was included in the BHA to gather data at the section mill and send it real-time to the surface for evaluation. This technology acquires downhole parameters such as weight on the tool, torque, revolutions per minute, bending moment, vibrations, pressure and temperature. The engineers then compare the downhole data with the surface data to understand what is occurring at the wellbore intervention tool. Therefore, they can make just in time decisions to optimise the operation.

9.2.4 Section milling improvements in Brent field

Shell aimed to increase the performance of the section milling operation throughout the Brent field P&A campaigns. Improvements have been made to the technique based on real field experience to reduce the overall time spent on the method.

For instance, the time to mill a window and set the abandonment cement plugs dramatically reduced throughout the campaigns. Considering the number of days spent in the reservoir abandonment phase from casing cut to tag of cement plugs, the P&A campaign reduced from 12 days in 2011 to less than 4.5 days in 2016 [40]. This improved performance was only possible due to different procedures that were optimised:

- Combined cement plugs: saved 2 days
- Combined mill and under-reamer: saved 1.5 days
- Optimised fluid strategy: saved 1 day
- Improved swarf handling: saved 0.5 day
- Operator competence and procedures: saved 0.5 days
- Enhanced knife design: saved 0.5 days
- Bridge plug on mill: saved 1.5 days

The trip-saving technology can reduce three trips to a single one using ProMILL assembly with integral bridge plug (Figure 31). The BHA was able to set a 9 5/8-in

bridge plug from a tapered mill, displace and condition the well, mill and under-ream a 150-ft section and complete the window in a single run.

Figure 31: ProMILL trip-saving system developed by Schlumberger [41].

Regarding the knife technology adopted, there was an improved consistency in manufacturing and brazing process. Also, titanium coating was applied to knives. After the trials were complete, results showed that the rate of penetration (ROP) was 4.5ft/hr while the target was 3ft/hr and the only 20-35% worn out knives over a 150ft window. It was seen also an improved consistency of swarf characteristics.

Fluid properties were also optimised for enhanced swarf recovery. It was used a viscous seawater based milling fluid optimised for easy bulk building, maintenance, environmental impact and cost. The milling performance was restricted by surface swarf handling capacity though. Figure 32 aims to show how fluids and swarf were handled on Shell`s Brent Bravo.

Figure 32: Fluids and swarf handling on Shell`s Brent Bravo [40].

9.3 Perforate, wash and cement

The Perforate, Wash and Cement (PWC) system was developed to eliminate some of the challenges faced by section milling operations. The PWC technology was created by HydraWell Intervention AS, a Norwegian company founded in 2008.

Although this method comprises one tool to perform different operations, these same operations have been successfully performed in Brazil. The PWC method is an improvement of the well-known squeeze cementing technique.

The method is able to create a permanent well barrier by using a system that perforates a section of un-cemented casing, washes the annular space and then mechanically places the cement across the wellbore cross section in a single run.

Before the PWC operation is conducted, cement evaluation logs are run to evaluate the condition of the annulus and the sealing capability of the material behind the casing. After the interpretation of the logs is complete, an interval is established for the plugs to be set. The minimum plug setting depth is usually where there are a free pipe and sufficient integrity of the formation.

As in section milling, the mud weight must be sufficient to maintain the stability of the open hole and exposed formation. However, since there is no swarf generation,

high viscosity fluids are not required to lift the metal debris from the wellbore. The PWC process reduces the occurrence of pack-off, which was one of the major issues from section milling. A safer working environment is created due to the lack of metal swarf, which is a material highly associated with lacerations. In addition, costs are greatly reduced since special topsides equipment for swarf handling is deemed unnecessary.

HydraWell has created two generations of tools that implement the PWC method. HydraWash is from the first generation and was developed to plug and abandon a single casing with one annulus. The second-generation PWC tool was named HydraHemera, it was invented to enable plugging across multiple annuli and also to have an improved washing tool. Both PWC tools can be run either as a single-trip or as a dual-trip and will be further discussed.

9.3.1 Operations for single casing & HydraWash system

The first generation of PWC tools was designed for plugging a well with one annulus. Hence, the production tubing is cut and pulled and other casing strings may have to be removed if several casings are present. Prior to the operation, an evaluation of the annular space is conducted.

The HydraWash system comprises a single run assembly that can be separated into three main pieces: a tubing-conveyed perforating (TCP) gun with disconnect, the HydraWash and the HydraArchimedes. They can be run on standard drill pipe and in the sequence as in Figure 33.

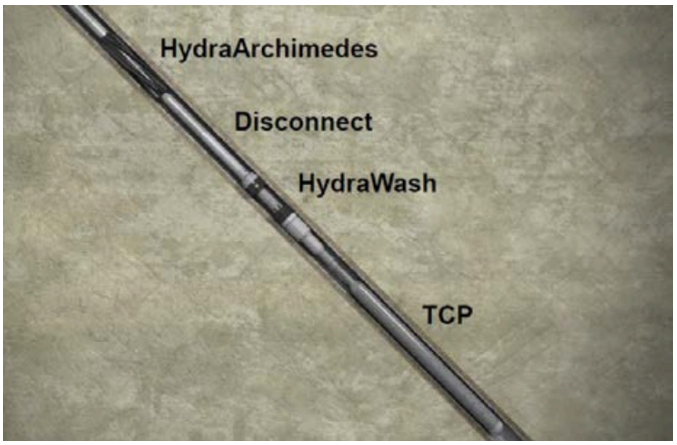


Figure 33: HydraWash system with single run assembly [42].

9.3.1.1 Tubing-conveyed perforating gun

The TCP gun is positioned at the bottom of the assembly. When the tool reaches the determined depth, the perforations will go off and punch holes in the casing and formation. The perforating guns are designed to shoot 12 shots per foot (SPF) with a 135/45-degree phasing. The top and bottom seven feet of the guns are loaded with charges that produce larger perforations. The uppermost perforations are larger to ease the washing behind the casing without exceeding the formation fracture pressure while the bottom perforations are larger to facilitate the displacement of mud by cement spacer and subsequent displacement of cement spacer by cement. The remaining charges operate based on the principle of limited entry perforating backpressure [43].

The length of the TCP gun depends on the desired perforation interval. Typically, the overall length of the gun is around 200 feet in order to place a 165-foot cement plug.

After the perforation is complete, the TCP gun is automatically disconnected from the tool and left in the hole. Therefore, a limiting factor of the single-run method is the length of the rat hole for leaving the gun. Rat hole is defined as the available interval where equipment can be left without disturbing the well barriers. In case the rat hole is not sufficient to accommodate the 200-foot TCP gun, the operation will be performed in a dual-run.

9.3.1.2 HydraWash

The HydraWash is a wash tool located above the TCP gun and is isolated between two elastomer wash cups. The tool aims to wash and clean out debris, old mud, barite, old cuttings and cement traces that may be present behind the perforated casing.

When tripping, the BHA acts as a large piston moving through the borehole and surge pressures are created when the string moves downward which can lead to loss of circulation. In order to prevent surge effects, the HydraWash has several large by-pass channels to divert the mud from below to above the wash cups while running in the hole. Therefore, the tool can be easily run in hole and the tripping speed depends only on the limitations of the TCP gun or the rig itself.

The wash cups are located above and below the wash tool (Figure 34) to isolate and seal off a short section of the casing during the washing phase. The distance of the two wash cups is designed to isolate a length of 1 foot inside the casing while washing the annular space. As a result of this and assuming that the TCP gun shot 12 shoots per foot, then 12 perforations are washed in one continuous movement of the tool.

Figure 34: Wash tool between two elastomer wash cups [44].

The outside diameter of the wash cups is larger than the inside diameter of the casing string to guarantee isolation while washing. Since they are manufactured with an elastomer material, it allows them to get compressed and squeezed when running in hole. After the washing phase, the wash tool is disconnected and the lower wash cup acts as a base for the cement plug to prevent cement slurry.

9.3.1.3 HydraArchimedes

The HydraArchimedes tool is connected directly above the wash tool and was developed to enhance the quality of the cross sectional plug. Its purpose is to rotate while cementing, forcing the wet cement through the perforations and to fill the annulus.

The principle behind the HydraArchimedes tool is that helical rubber blades act on the cement both mechanically, by squeezing the wet cement through the perforations, and also hydraulically, by generating high and low-pressure regimes. Figure 35 presents the tool and its blades.

Figure 35: HydraArchimedes and blades [38].

Each tool is able to treat up to 25-meter perforations, and then several can be combined to achieve the desired length. The cementing operation takes place while the tool is rotated and pulled out of the hole.

9.3.1.4 The operation

The PWC tool consists of a single run assembly containing a TCP perforating gun with disconnect, the HydraWash jetting tool with by-pass channels for easy running in, a cementing stinger and the HydraArchimedes cementing tool.

Once the assembly is at the desired plug-setting depth, the perforating guns are fired, as seen in Figure 36, and the perforating assembly is automatically dropped.

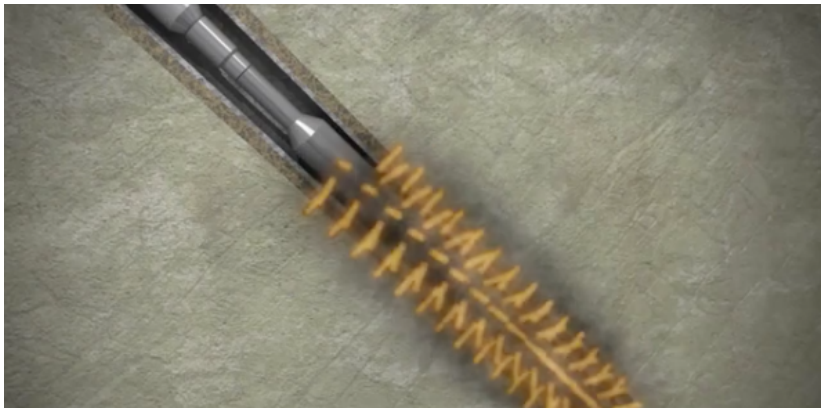


Figure 36: Tubing-conveyed perforating gun being activated in HydraWash system [42].

The Figure 37 shows the holes that were punched in the casing by the perforating guns. The TCP gun is not represented at this time since it was disconnected and dropped after the perforation.

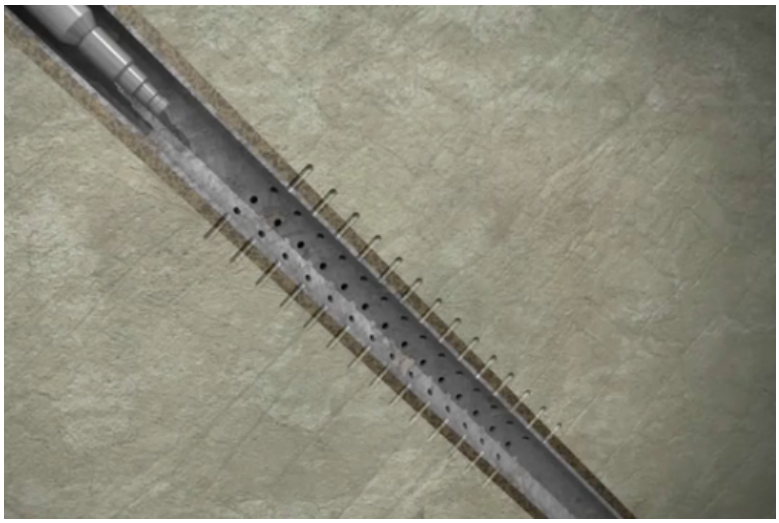


Figure 37: Holes punched in the casing by the tubing-conveyed perforating gun [42].

After the perforation is complete, the assembly is placed in the upper area of the perforations. A ball is dropped to stop circulation through the washing tool, the procedure seals off the bottom of the wash tool and opens a sliding sleeve to direct circulation between the wash cups. The washing is done across the perforated interval while the tool moves downward as seen in Figure 38 [34].

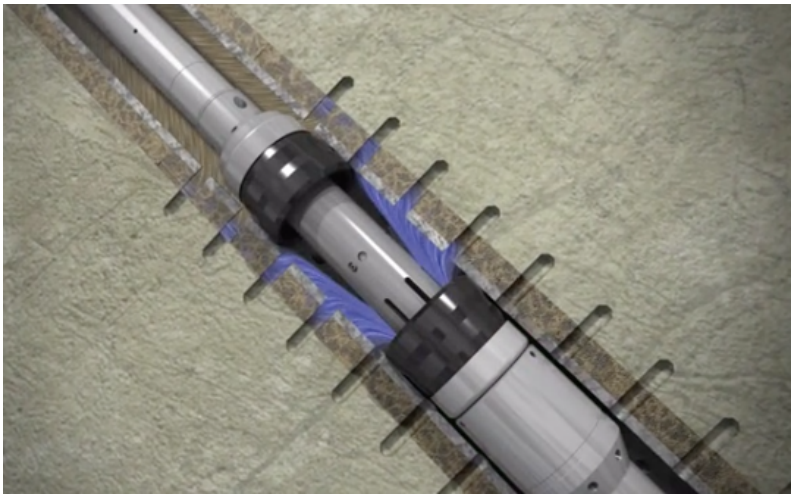


Figure 38: Washing tool being run downward while cleaning the perforated interval [42].

The washing fluid is pumped and forced with high velocity into the annulus to clean the annular space through the perforations between the wash cups and also the annular space above the top wash cup. When mid-gun charges are designed, they aim to create perforations with determined diameters that could generate backpressures between 55 to 75 psi when pumping washing fluid through the perforations.

The pressure readings are the parameters used to control the washing process of the operation. The pressure readings in the washing fluid increase when particles (e.g. cement residues, debris, old cuttings or old mud) are encountered along the perforations. It happens due to the resistance created by the particles against the flow. At some point, the particles will be circulated out, no longer blocking the perforations that will be finally clean, the flow rate of the washing fluid will increase and only then the washing tool will move. Therefore, when a pressure peak is observed, the wash cups will not be moved to a new position until the pressure decreases and stabilises which indicates that cleaning is achieved. The pressure curve in Figure 39 represents a washing sequence; high-pressure readings indicate that there is a flow restriction while low-pressure readings indicate that the perforations are opened and debris are removed.

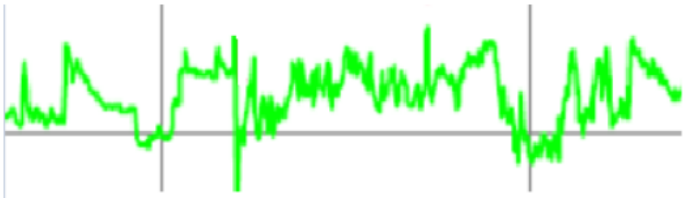


Figure 39: Typical pressure washing curve [21].

Even though OBM can provide a higher washing rate, industry experience has shown that it has a tendency to contaminate the cement. This is the reason why WBM is more recommended to the operation. The washing rate is determined by the ECD, which is a function of the formation fracture gradient, fracture pressure, well geometry and rheology [21]. The ECD cannot exceed the fracture gradient of the exposed perforations since it would lead to losses while circulating and well control problems.

When the washing tool reaches the bottom of the perforations interval, the washing process is repeated with the tool moving upward while pumping at the maximum loss-free rate. The maximum loss-free rate is determined when the

circulation pressure equals the fracture pressure, which means that the washing fluid is at its maximum rate. This rate is obtained by simulation during the planning phase prior to the operation [19].

While the washing tool is run upward, all the unwanted particles that are still remaining in the annulus are replaced by clean mud. Once the annular space has been entirely cleaned, the wash tool is lowered to the bottom of the perforations and a spacer fluid is pumped into the area.

The wash tool is then positioned below the perforations interval and a command is sent to disconnect the wash tool and convert the assembly to a cement stinger. As seen in Figure 40, the wash tool is disconnected from the assembly and left below the perforations, its upper wash cup acts as a base for the cement plug since it has sufficient contact force against the casing.

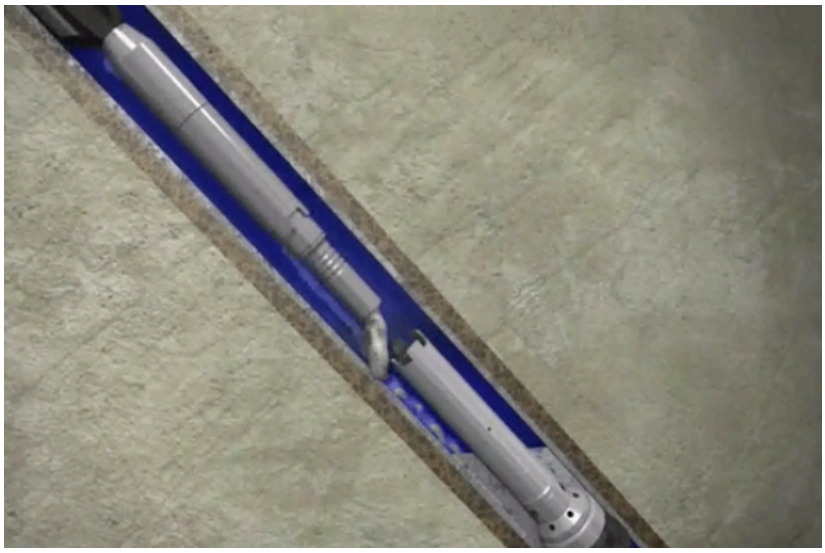


Figure 40: Cement stinger pumping cement and wash tool functioning as a base for the cement plug [42].

The cement is pumped through the cement stinger and fills the area. The rotation of the HydraArchimedes tool forces the cement through the perforations as the assembly is pulled out of the hole, ensuring that a uniform cement plug is set. The workstring can be used to wash downward to the top of the cement for tagging and pressure testing.

9.3.1.5 Challenges

The HydraWash technology implementation within the P&A industry achieved its peak in 2012. The number of plugs set using this technology has gradually decreased since then.

One of the main challenges faced by the HydraWash technology is the large diameter of the washcups. It is difficult for the HydraWash tool to enter wells that have a reduced inner diameter due to collapsed sections. In addition, during perforations some small burrs with sharp metal edges are created on the inside wall of the casing caused by the backfiring of steel. These sharp edges are damaging for the wash cups elastomer material while the wash tool moves up and down. When worn out wash cups are experienced, unnecessary time is spent for tripping the assembly in and out to replace the wash cups.

The HydraHemera technology was developed to tackle at least one of the drawbacks experienced by the HydraWash system.

9.3.2 Operations for double casing & HydraHemera system

The HydraHemera system is considered the second generation of the PWC method implemented by HydraWell. It was developed to enable plugging a well across multiple annuli without performing a section milling operation. While the HydraWash tool is able to clean only one annulus in a satisfactory manner, the HydraHemera system is designed to perforate, wash and cement multiple annuli at the same time. The improvements implemented in this new washing technology also led to the development of the HydraHemera system for single casing.

The HydraHemera system for double casing consists of a single run assembly containing a bullnose with circulation, the HydraHemera jetting tool, the HydraHemera cementing tool and the HydraArchimedes cementing insurance tool.

Firstly, before the assembly is run, a drillable bridge plug (e.g. EZSV) must be set inside the casing since the tool does not include an integrated disconnect plug. Following this, the HydraKratos and the TCP gun are run. The HydroKratos is only used if there is a need to have a foundation for the casing cement that will be set inside the annuli. Lastly, the HydraHemera tool is run in hole to perform the washing and cementing operation.

9.3.2.1 HydraKratos

The HydraKratos tool, presented in Figure 41, creates a foundation for the annulus cement plug when establishing a cross-sectional barrier with HydraHemera system. It is only used when there is no annular cement in either of the annuli to act as a base for the upcoming annulus cement barrier. The tool is designed for the actual casing configuration, it contains a charge that generates sufficient energy to expand casing strings into the outside formation closing off any conduit in order to prevent slumping in the annuli.

Figure 41: HydraKratos tool [45].

The tool can be run in conjunction with TCP guns or on a single run on pipe. In case it is set below the TCP guns, at the same time that the perforating guns are fired, the HydraKratos is exploded to ensure a casing-to-formation seal, which forms the base for the cement plug in the inner and outer annulus. The TCP gun is dressed with big-hole charges, the perforation shots are as large and tightly spaced as the casing allows them to be. Figure 42 aims to present the moment when the perforating guns are activated. The tools are then pulled out of the hole and the HydraHemera assembly is run in hole.

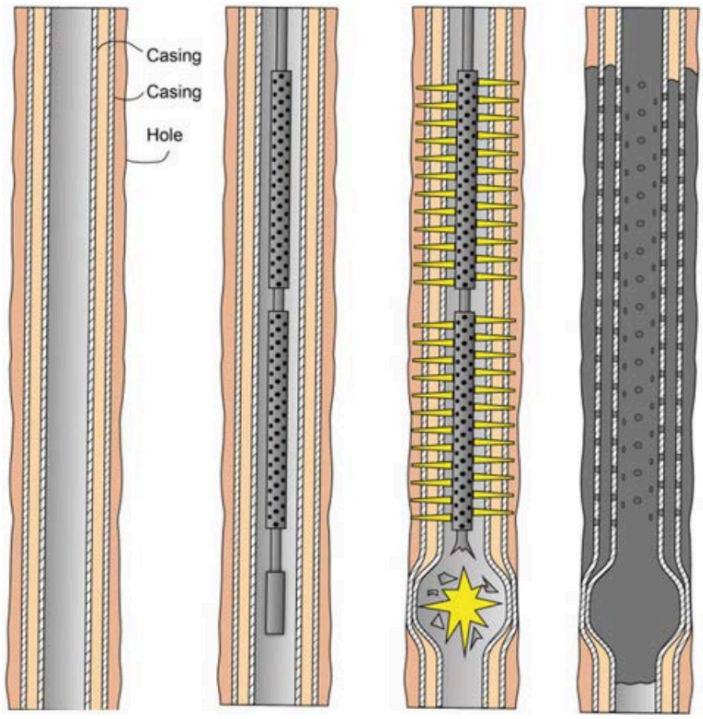


Figure 42: HydraKratos and perforating guns being activated [19].

9.3.2.2 HydraHemera

The HydraHemera system enables the washing behind double casings. Figure 43 presents the single run assembly, it comprises a bull nose at the bottom to allow circulation while running in hole, followed by the HydraHemera jetting tool, the HydraHemera cementing tool and the HydraArchimedes tool.

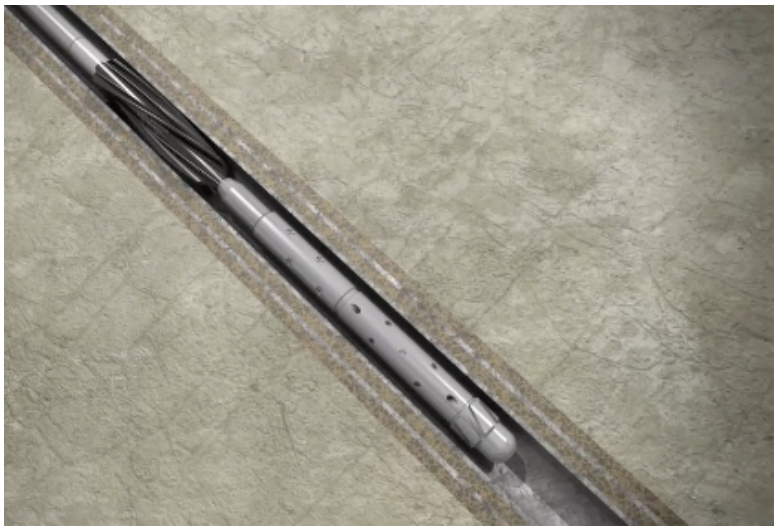


Figure 43: HydraHemera system [42].

The jetting tool is used for washing and cleaning the unwanted particles (e.g. debris, old cuttings, old mud or cement traces) in the annuli behind the perforated casings. It features jet nozzles positioned at irregular angles and engineered for an optimal configuration and exit velocity. This feature creates jets of mud that are deflected between the different annuli, as seen in Figure 44, cleaning all voids and cavities of old mud and moveable debris. Hence, the jets are able to penetrate and clean behind the double perforated casings, providing the required conditions to the annuli to accommodate the plugging material.

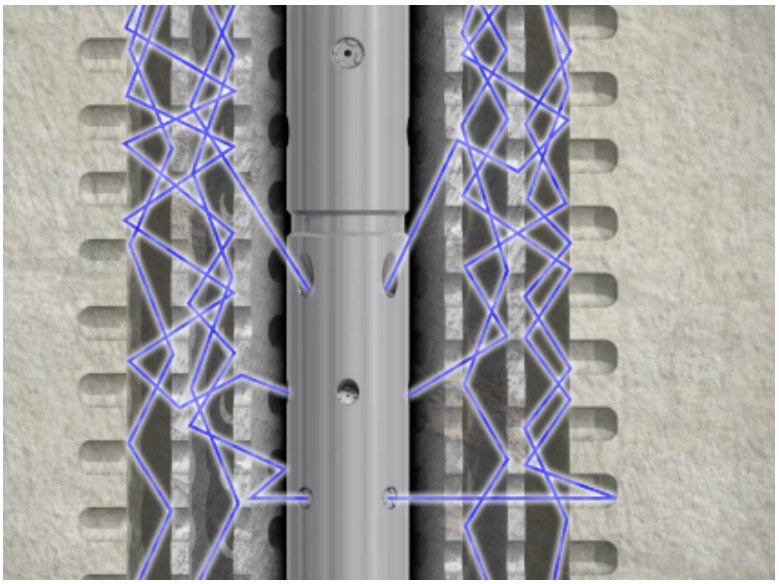


Figure 44: HydraHemera jetting tool with nozzles engineered for optimal configuration [42].

The cementing tool features four nozzles with diameters that are larger than the nozzle diameters of the jetting tool in order to avoid cement dehydration and nozzle plugging.

9.3.2.3 The operation

As previously discussed in chapter 9.3.2.1, before running the HydraHemera tool it might be necessary to run HydraKratos first to provide a base for the annuli cement barrier. The assembly with the HydraKratos tool connected below the TCP gun is lowered into the hole until the TCP gun is positioned in the P&A area. Figure 45 presents the configuration with a bridge plug installed at the bottom to function as

a mechanical base for the internal cement barrier, also the assembly with the TCP gun positioned at the determined P&A area followed by the HydraKratos tool.

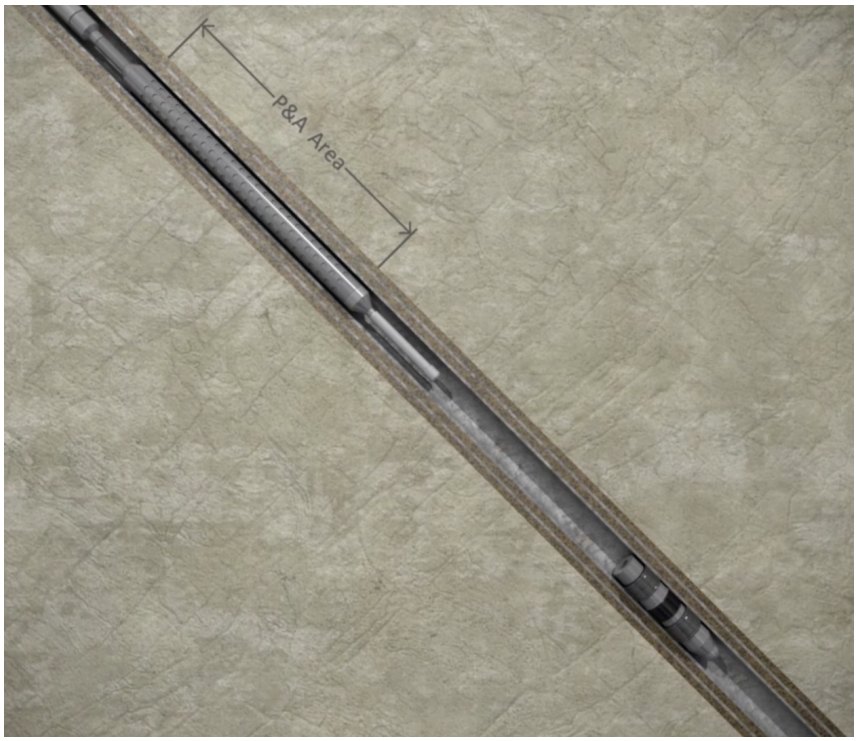


Figure 45: Perforating gun in the plug & abandonment area with HydraKratos below it [42].

The tools are then activated by a ball drop mechanism. The energy from the explosion of the HydraKratos is calibrated to expand both casings ensuring a casing-to-formation wall fit and creating a seal. Figure 46 shows the configuration of the wellbore after the guns were fired. The perforations are in the P&A area and below them there is the base for the annuli cement plugs created by the HydraKratos with the expansion of the casing strings.

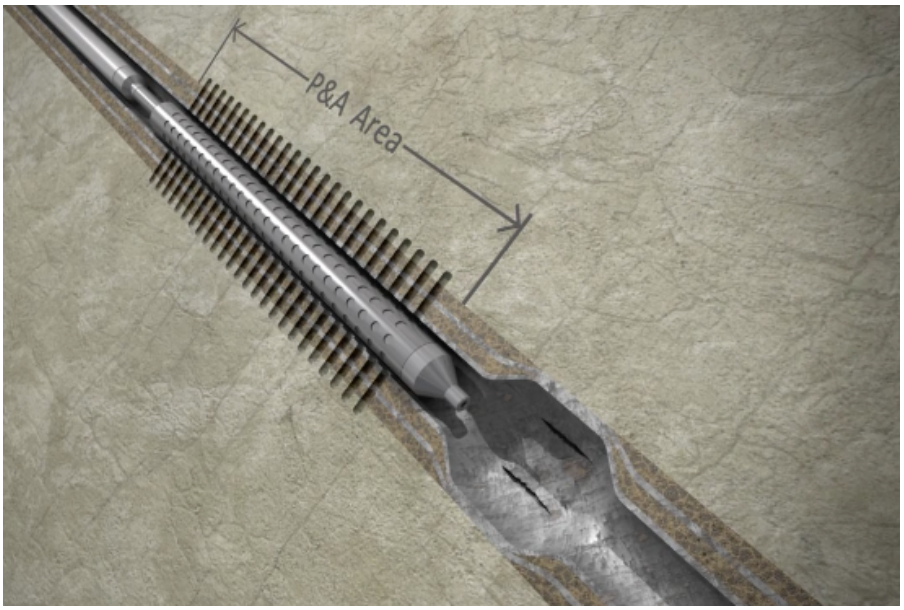


Figure 46: Perforations and the base for the annuli cement plug created by HydraKratos [42].

The drillstring is then pulled out of the hole and the HydraHemera system string is run in hole. Once the string is positioned at the top of the perforations, a ball is dropped to activate the circulation through the jetting tool and the washing process can then begin.

The flow is directed through nozzles creating high-energy jets of mud that are able to clean the annuli behind the perforated casings. Debris, old mud, barite or old cuttings are removed and replaced by clean mud. Figure 47 shows the HydraHemera jetting tool cleaning the annuli while moving downward.

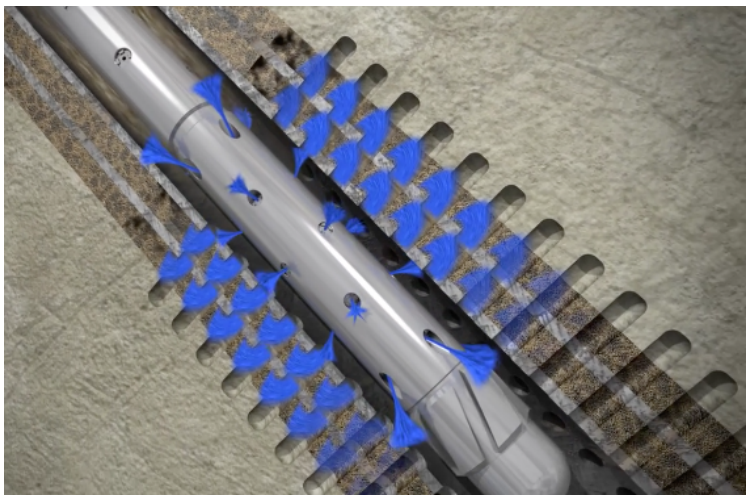


Figure 47: HydraHemera jetting tool moving downward and washing the annuli [42].

Once the annulus space has been thoroughly cleaned, the assembly is lowered to the bottom of the perforations and the jetting tool is used to displace spacer fluid into the area as presented in Figure 48.

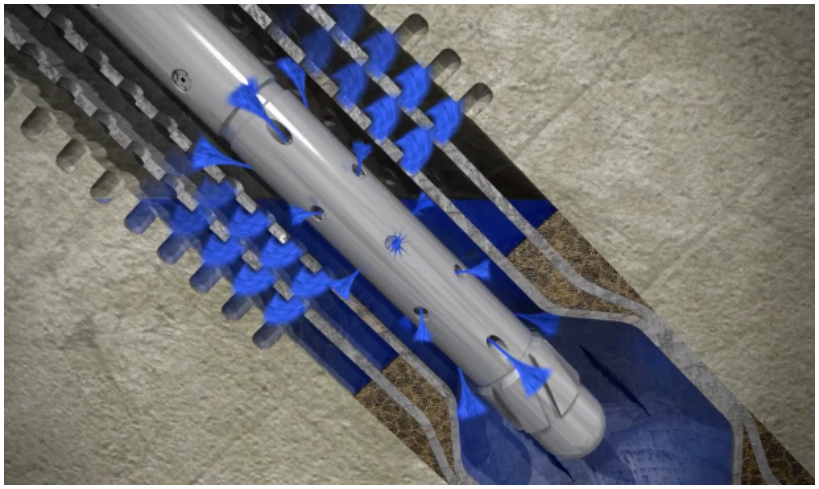


Figure 48: Spacer fluid flowing through the HydraHemera jetting tool to fill the area [42].

After the area is filled with spacer fluid, the HydraHemera system is lowered next to the bridge plug and the ball drop mechanism is used to divert the flow through the HydraHemera cementing tool. Figure 49 represents the moment when the cementing tool starts pumping cement. The HydraHemera cementing tool is located above the jetting tool and features larger nozzle diameters to prevent cement dehydration and plugging of the nozzles.

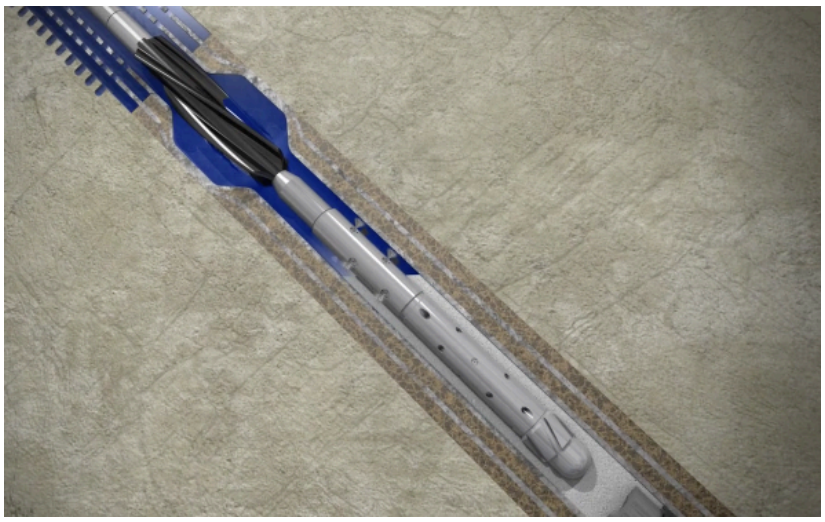


Figure 49: HydraHemera cementing tool pumping cement [42].

The cement flows through the perforations, fills the inner and outer annulus area and also inside the casing. The rotation of the HydraArchimedes tool forces more cement into the perforations ensuring that a uniform plug is properly set in the cross section.

To sum up, with this method the EZSV that is set prior to the operation acts as the base to prevent slumping of the internal cement plug. While the seal created by the HydraKratos is the base for the annular cement plug.

10. Recommendations for the industry

The aim of this chapter is to provide recommendations for the industry to establish procedures that could simplify the P&A activities. It was already brought up for discussion throughout this work that this phase must be extensively planned with a multidisciplinary approach. There are certain strategies though that could be adopted during initial stages of well design that would be extremely valuable for choosing the most accurate approach in abandonment phase, hence reducing uncertainties, time and costs.

The first recommendation is to consider the abandonment requirements at the earliest stages of the completion design. For instance, when there is a minimum length requirement for annular barriers to provide a permanent annular sealing, then this determined length should be incorporated to the well design. During well construction, the rig is already in place and cementing operations will be performed, so it is reasonable to implement the abandonment requirements at this phase.

Another recommendation that could simplify the P&A activities is to verify the annular barriers after they are set. When the primary cement job is verified by logging and the documentation is available for P&A planning phase, the abandonment approach can be much more easily defined. In case there are no evidences from logs and the casing cement is not verified, then will be necessary to cut and pull casings since current logging technology is unable to verify cement quality through multiple casings. The procedure of cutting and pulling casings is a heavy lift operation that requires a rig; hence high costs are related to it. The remedial options (e.g. section milling and PWC) used to reestablish external barriers are complex and time-consuming. In order to avoid them, operators should focus on achieving a successful primary cement job and performing logs to verify it. Then, a more simple and effective P&A operation can be delivered. Lately, operators already embraced this recommendation and the verification by logging is performed.

Regarding the production tubing, they are usually cut and pulled during P&A operations mainly due to two reasons: to log the cement bond behind the production casing, or if there are cables and control lines clamped to it. Even if the annular barrier of the production casing is verified by logging, it would still be necessary to cut and pull the tubing because currently there is no technology able to remove the control lines without pulling the tubing. And as discussed previously on this work,

these lines cannot be part of a permanent well barrier since they could create vertical leak paths in the plugging material. The recommendation stands again for the fact that it could be extremely beneficial if the completion design considers future abandonment. In this case, the well could be designed to leave a determined section without control lines so the cement or any other plugging material could be set at that interval. Instead of being clamped to the production tubing, another solution would be to have the control lines attached to it in a way that they could be more easily removed. To sum up, with these recommendations the operation of cutting and pulling the production tubing could be avoided, a through-tubing abandonment would be performed and the P&A costs could be reduced.

The wellhead removal is also a relevant topic to be discussed. For deepwater wells, NORSOK Standard D-010 Rev.4 [13] reveals that it may be acceptable to leave or just cover the wellhead structure. The recommendation of this work regarding deepwater wells in Brazil is to leave the wellhead in place. Even though permanent plugged wells are abandoned with a lasting perspective, in case there is a need to intervene in the future, to have the wellhead in place will allow the intervention to be performed more efficiently. Furthermore, the Brazilian regulation [14] does not consider that the wellhead removal is mandatory.

11. Conclusion

The main focus of this work was to investigate how the P&A operation is performed worldwide and what are the available techniques that are currently implemented, assessing their challenges and improvements. Moreover, to understand the Brazilian regulation regarding permanent well abandonment requirements and how international guidelines can also provide a support. The release of the Guidelines for Well Abandonment issued by IBP in 2017 is a milestone for the P&A operations in Brazil. It provides the best practices of the industry adapted to the Brazilian scenario and finally the country has a guideline on well abandonment requirements developed with the same quality of the international guidelines.

The cement has been considered the most appropriate plugging material for abandonment purposes. However, service companies have been trying to develop new materials that could overcome some of the issues faced by cementing operations. Even though it is believed that ThermaSet has superior properties, it is still important to verify its long-term capability. One of the greatest challenges related to introducing ThermaSet is the reluctance of the industry to try something new, since P&A sector already comprises high-risk activities a more traditional plugging material is preferred.

Regarding the P&A techniques available, traditionally section milling has been the most used method in the North Sea. Shell's Brent field P&A campaigns made improvements and increased the efficiency of this method due to different procedures that were optimised. One of the main issues related to the section milling operation is the swarf generation that can damage the BOP and can cause the occurence of pack-off. The PWC technology aims to eliminate this challenge since no swarf is generated. It is considered an improvement of the well-known squeeze cementing technique and it is believed that PWC is a faster and more cost effective P&A method, especially when used on multiple casing strings. However, it is challenging to verify a plug set over two annuli since it is not possible to log through multiple casings.

Ultimately, P&A should be considered at the earliest stages of the well design. The ideal case is to have a verified and sufficient primary cement job behind the casing and then P&A operations could be less demanding and expensive. If remedial actions are still needed, the P&A techniques are available to provide a proper sealing and long lasting solutions.

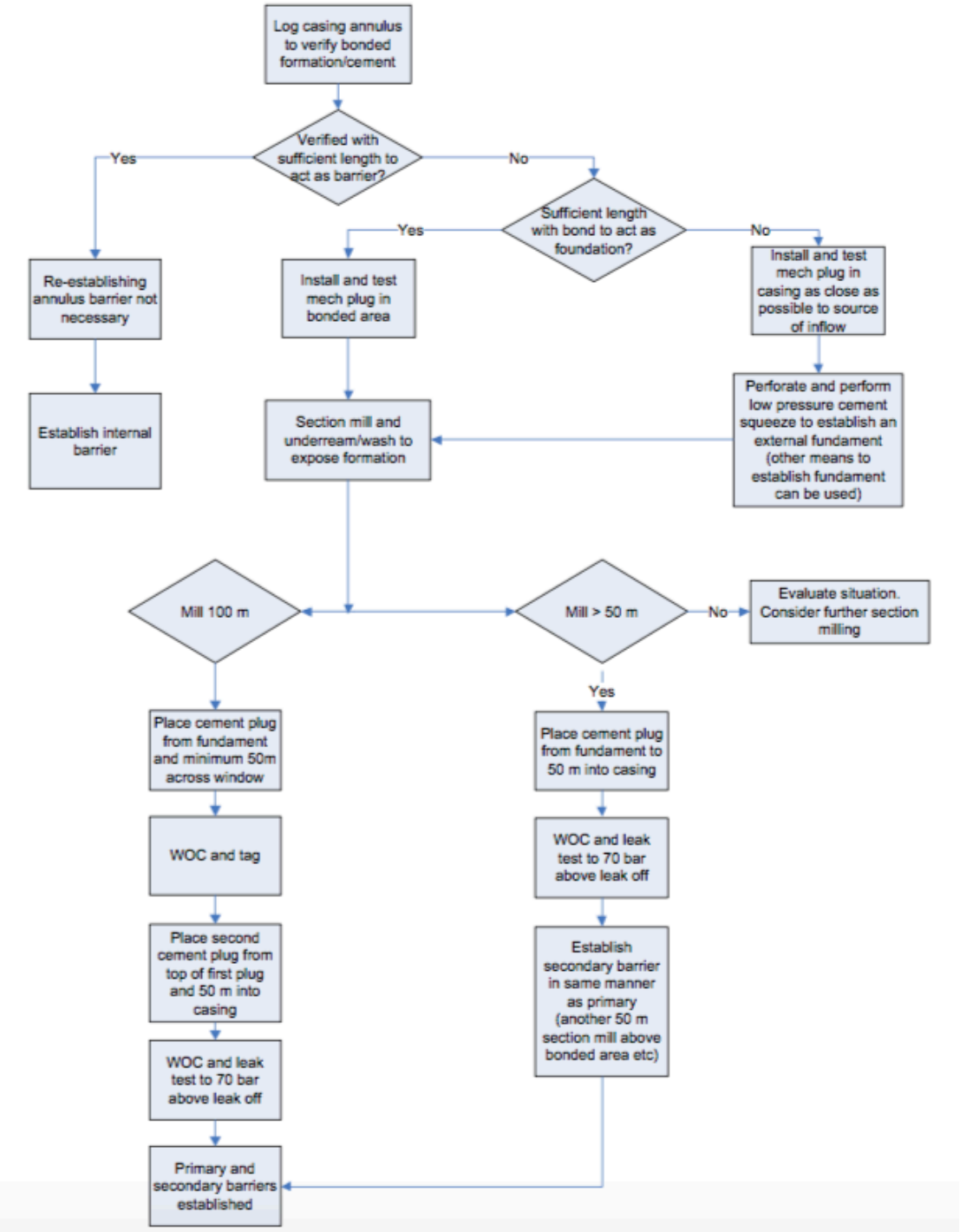
Appendices

Appendix A: Guidance on verification of the well barrier requirements [16]

Single permanent Barrier (primary & secondary)				
Barrier type	Verification			
	Well bore / tubing		Casing annulus	
	Position	Sealing capability	Position	Sealing capability
Through-tubing	Tag	Pressure test	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Refer to chapter 6.2 of this work
Through-tubing on a mechanical barrier	Tag cement, or measure volume to confirm depth of firm barrier, subject to risk assessment	Pressure test of mechanical barrier after release and pressure test cement in tubing and annulus separately	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Refer to chapter 6.2 of this work
Cased hole	Tag	Pressure test	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Refer to chapter 6.2 of this work
Cased hole on a mechanical barrier	Tag cement, or measure volume to confirm depth of firm barrier, subject to risk assessment	Pressure test of cement barrier or mechanical barrier after release	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Refer to chapter 6.2 of this work
Open Hole	Tag	N/A	N/A	N/A

Permanent combination barrier				
Barrier type	Verification			
	Well bore / tubing		Casing annulus	
	Position	Sealing capability	Position	Sealing capability
Through-tubing	Tag	Pressure test	Good cement bond, minimum 200 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Refer to chapter 6.2 of this work
Through-tubing on a mechanical barrier	Tag	Pressure test of mechanical barrier after release and pressure test cement in tubing and annulus separately	Good cement bond, minimum 200 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Refer to chapter 6.2 of this work
Cased hole	Tag	Pressure test	Good cement bond, minimum 200 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Refer to chapter 6.2 of this work
Cased hole on a mechanical barrier	Tag cement	Pressure test of cement barrier or mechanical barrier after release	Good cement bond, minimum 200 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Refer to chapter 6.2 of this work
Open Hole	Tag	N/A	N/A	N/A

Appendix B: Decision tree for section milling to establish permanent barriers [13]



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