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A Study of Possible Approaches for Considering Well Abandonment in the Well Design Stage

Master's Thesis by

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Abstract

There are many fields on Norwegian Continental Shelf (NCS) that approach end of their design life. Based on feasibility studies, life of some fields is prolonged while it is shortened for others.

Since early days there was strong focus on drilling wells faster. Safety aspect came some time later. Little or no attention at all was given for future well abandonment activities. During the last decades, a lot of experience has been gained by operator companies when it comes to permanently plugging both old and 'newly' designed wells on NCS. Some old wells were abandoned in the manner of days while others required extensive resources to abandon. The common challenges were ranging from lack of basic well data to well design and subsurface conditions that were unfavourable for well abandonment, hence requiring additional efforts.

Well abandonment does not generate direct revenue neither for operator companies nor for society. This activity rather represents a huge cost, which should be minimised. In recent years authorities has started to emphasize the importance of considering well abandonment in well design stage and urged industry to cooperate and share the experience in order to find the best and cost efficient solutions for well abandonment.

This thesis is aiming to find and highlight factors that are of importance for considering well abandonment in well design stage. To do so, literature study was conducted which was later on supplemented with feedback from the industry through a questionnaire.

Several important factors have been identified and general recommendations have been outlined.

One of conclusions of the study is that not many adjustments to well design are necessary in order to facilitate future well abandonment when NORSOK Standard D-010 is followed.

Improvement potential of the Standard is also indicated.

Preface

This thesis is submitted in fulfilment of the requirements for the degree of Master of Science at the University of Stavanger.

I would like to thank my supervisor Fatemeh Moeinikia for kindness, openness and great support throughout the thesis writing. Your availability for discussions outside the office hours deserves additional highlight and was much appreciated.

I would also like to thank wonderful people at operator companies who used their time to provide answers to my questions and of course their management who allowed this information to be shared.

Finally, I would like to thank my wife Justina and daughter Celina for encouragement in pursuing the degree and for patience and support throughout years.

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Nomenclature

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in	inch
m	metre

List of Abbreviations

3D	three-dimensional
AOC	Acknowledgement of Compliance
API	American Petroleum Institute
BHA	Bottom Hole Assembly
BI	Bond Index
BOP	Blowout Preventer
CBL	Cement Bond Log
CMR	Combinable Magnetic Resonance
csg.	casing
CWBE	Common Well Barrier Element
DHSV	Downhole Safety Valve
e.g.	example gratia
EAC	Element Acceptance Criteria
ECD	Equivalent Circulating Density
FG	Fracture Gradient
GL	Gas Lift
GOM	Gulf of Mexico
GOR	Gas to Oil Ratio
HC	Hydrocarbons
HPHT	High-Pressure/High-Temperature
HSE	Health, Safety and Environment
HXMT	Horizontal Christmas Tree
LWD	Logging While Drilling
LWIV	Light Well Intervention Vessels
MD	Measured Depth
NCS	Norwegian Continental Shelf
NMR	Nuclear Magnetic Resonance
NORSOK	Norsk Sokkels Konkuranseposisjon

NPD	Norwegian Petroleum Directorate
NPT	Non-Productive Time
OBM	Oil Based Mud
P&A	Plug and Abandonment, Plugged and Abandoned
PDC	Poly-Diamond Crystalline
PP	Pore Pressure Gradient
PSA	Petroleum Safety Authority Norway
PWC	Perforate, Wash and Cement
RKB	Rotary Kelly Bushing
RLWI	Riserless Light Well Intervention
s.g.	specific gravity
SCP	Sustained Casing Pressure
SF	Safety Factor
SWAT	Suspended Well Abandonment Tool
TD	Target Depth
TOC	Top of Cement
TVD	True Vertical Depth
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
USA	United States of America
VDL	Variable Density Log
w.r.t.	with regards to
WB	Well Barrier
WBE	Well Barrier Element
WBM	Water Based Mud
WBS	Well Barrier Schematic
XMT	Christmas Tree

1 Well Planning & Well Design

1.1 Historical Overview

1.1.1 The Beginning

For centuries, humans made use of naturally seeping petroleum from the ground. No planning was required and use of seeps was limited.

Through evolution, humans discovered oil distillation principles and extended applications of seeping petroleum on a small scale. However, it was not until 18th century, when considerable investments in oil drilling and refining were made. Consequently, businesses were able to obtain petroleum products in sufficient quantities. Well planning was based on locations of existing seepages and well know petroleum locations that actually were discovered by chance. Occasionally, it even included elements of "wizardry" where a man would point at the ground relying on his "powers" and would hit the spot by accident. Wells were, basically, holes in the ground ranging from several meters to several tenth of meters [1-3].

Early well design was employing wood to case the well until some decades later steel tubulars became available. Introduction of cement as a sealant, in the beginning of 19th century, contributed to the new methods for well design [4].

1.1.2 The Evolution

Well planning and well design has evolved significantly since then. Until 1990's all disciplines within well planning and well design were considering their own objectives and tasks. They worked separately and there was little collaboration and experience transfer. Geologist was responsible for subsurface mapping. Geophysicist was refining geological interpretation based on the seismic data. After the drilling target was defined, the project was handed further to drilling engineer for well design. On many occasions, data interpretation varied from professional to professional and important assumptions and interpretations were not challenged by technical analysis. If drilling engineer was concluding that the target was unreachable, the work needed to be re-done for all disciplines. This contributed to increased project cost. Once casing program was developed, the service companies were called in to design mud and cement programs. All disciplines would meet together and collaborate only in case of unforeseen events during the drilling activities.

Contribution of such collaboration was however limited, considering the timeframe and communication means [5].

1.1.3 Development in Recent Decades

Computer hardware and software developments have seen a major leap at the end of 19th century. First, geological and geophysical programs merged into one integrated suite that significantly improved workflow in exploration work. The industry has noted the benefits of such merge and hence a desire to integrate drilling into the same workspace arose. It was sought that such integration would result in improved workflow, as all disciplines would use a common project database.

Geologist and geophysicist would select the drilling target and visualise the proposed well trajectory. Engineer would then employ drilling engineering tools to choose kick-off points and optimise the well path taking drilling constrains into consideration. Because of the thought that the process would became a real-time interaction (where all assumptions are being shared and challenged among the disciplines), the drilling targets would be selected more efficiently and require less time than previously [5].

Such software was developed and has since been used and further optimised. Although different operator companies use proprietary or third party software that has different built-in modules and functions, they all share the same basic idea of information availability across the disciplines.

1.2 Well Planning

Well planning practices and procedures vary among the operator companies, from country to country and depend on well location (onshore or offshore).

Well planning activities are typically initiated once seismic data has been interpreted and subsurface potential or need for reservoir support has been identified. This information helps to justify a new well in terms of extra production and/or economic value. The well proposal document is then made and is presented to the management for approval. When budget for drilling the new well is approved (approval of expenditure), the work on detailed drilling program would start [6].

A multi-disciplinary team is commonly responsible for well planning and may consist of geoscientist, geologist, reservoir engineer, drilling engineer and completions engineer. The team would then utilise computer software with three-dimensional (3D) visualisation environment in order to choose the best well path that reaches the reservoir target [6, 7].

A good example of such software is Roxar's Reservoir Management Software (RMS™). The software comprises a wide range of tools and modules for reservoir geophysical and geological analysis; reservoir simulations; well planning as well as real-time monitoring and geosteering [8].

The software allows team members to focus on the conceptual solutions and not struggle with the details. Based on the initial input from the user, the software automatically generates driller's target(s), well path, and performs feasibility analysis of the design. Geological target selection is performed in 3D context in order to secure a good understanding of subsurface environment. This stage requires most input from all disciplines e.g. direction, curvature limits, formation tops and fluid contacts to name a few. The process follows by defining geological target boundary and well path design given a certain amount of input. Although well path is generated automatically by the software, presented results are quite detailed and fit well into the overall 3D-model of subsurface. Lastly, well path evaluation is performed in terms of wellbore position uncertainty using surveying module. This ensures that the driller's target is located in the sub-volume of the geological target and that the well will not collide with any nearby well.

The software allows for complete re-planning of the well if well slot location is moved, as initially generated well path is a consequence of predefined relative position, target and the drilling programme with its constrains [9].

Introduction of the new workflow to the real projects results in significant reduction in cycle time to plan the well (as only viable alternatives for all disciplines are being analysed) [6, 9].

After the well path has been chosen, Pore Pressure Gradient (PP) and Fracture Gradient (FG) along the well path are estimated. Most likely, low-side and high-side pressure gradients and integrity estimates are also stated and plotted. Those estimates play a key-role to a successful well design [7].

1.3 Well Design

The requirement to make wells more cost effective has resulted in significant improvement in equipment and technology. However, introduction of the concept of deviated well has brought more challenges that needed to be overcome. In order to achieve the objective for modern wells the emphasis is put on the well design process.

As a good practice, each new well should be designed individually based on the experience from earlier or nearby wells. The design should be easy to implement and it should also provide flexibility in case of difficulties and changes introduced during the drilling phase [10].

Understanding of subsurface environment, that the well is to be drilled in, makes a basis for a well design. It is also important to understand and account for uncertainties and interpretations made during the initial well planning phase [11].

The chosen well path together with PP and FG forecasts create a framework for well design. This framework in turn defines a series of interrelated challenges and hazards for drilling the well:

- Well type
- Wellbore stability
- High-pressure/High-temperature reservoirs
- Casing architecture
- Casing design
- Drilling fluid selection
- Borehole cleaning
- Drillstring design and bit selection
- Various hazards

The drilling and completion engineers would then work together to address these and other challenges and deliver a well design with a minimum life-cycle cost and acceptable level of design and installation risk [6, 7].

In addition to the challenges and hazards presented above, the following activities must also be considered and planned for in the well design phase:

- Cementing
- Logging
- Well completions

1.3.1 Well Types

Two most common ways to classify the well is by the purpose of the well [12, 13] and by the way it is drilled [14].

Classification by the purpose of the well:

- Exploration well:
  - *Wildcat well* - drilled to establish the existence of hydrocarbons (HC) in subsurface.
  - *Appraisal well* - drilled when deposits have already been discovered by a wildcat well with the aim of establishing the extent and size of the deposits.
- Development wells:
  - *Production well* - drilled to produce HC or water for re-injection purposes.
  - *Injection well* - drilled for reservoir pressure support (as a mean of effective displacement of HC) and for injection of products generated by drilling/production activities.

Classification by the way well is drilled:

- *Conventional well.* Conventional (vertical) drilling is the simplest way to drill the well. The well is located at the stratigraphic top of the reservoir and drilled to target depth. This was the only way to drill the well until the technique to deflect the well was pioneered and perfected. Even then, most of the onshore wells were drilled as a vertical well due to cost issues.
- *Deviated well.* This well type is mainly associated with offshore development. To drill the deviated well, one can use:
  - Turbine and bent sub (sliding mode) - only bit rotates.
  - Rotary steerable assembly - the whole drilling string rotates.
- *Horizontal well.* In this type of well, reservoir section is drilled at a high angle in order to keep the well within a specific target zone. Horizontal wells are drilled in special configurations and are not exactly horizontal but rather have an angle greater than 80 degrees. Despite

difficulty in landing the horizontal well in target zone and other challenges, this well type often ends up to be the best producer in the field compared to conventional and deviated wells.

- *Designer well*. This well type often has high angle and has more than one intended subsurface target. Although the cost of such well is high, the well is still cost effective, as the overall cost to drill separate wells for each target is much higher than the cost of a single designer well.
- *Multilateral well*. This well type is a cost effective way to develop the field as the well has a main bore and several branches that kick off in different directions in the subsurface.
  When it comes to design of such wells, it is recommended to apply 'top-down' developing sequence in order to minimize the risk of losing deeper section [15].

1.3.2 Wellbore Stability

In past decades, wells became longer and more deviated. It was observed that regional and local stresses as well as weak/unconsolidated formations affect wellbore stability. Occurrences of tight hole and borehole collapse became more frequent and often result in Non-Productive Time (NPT). Wellbore stability issues has since became a central topic as they account for approximately 10% of time required to drill a well.

Although there is no single solution to the problem, wellbore stability issues can be greatly minimized if proper mud density is used in drilling [10].

The wellbore stability issues are also relevant for well completions and hence must be accounted for.

1.3.3 High-Pressure/High-Temperature (HPHT) Reservoirs

Norwegian Petroleum Directorate (NPD) defines a well as HPHT well when [16]:

- Well is deeper than 4000 mTVD (metres True Vertical Depth), and/or
- Shut-in wellhead pressure exceeds 690 bar (10 000 psi), and/or
- Static bottom hole temperature is higher than 150 °C

The NORSOK Standard D-010 classifies a well as HPHT well if shut-in wellhead pressure exceeds 690 bar (10 000 psi) and the static bottom hole temperature is higher than 150 °C [17].

NPD definition of HPHT well might seem too conservative in terms of depth; however, this will come at hand when designing the well.

The approach in designing HPHT well is similar as to any other well. But unlike for conventional wells, the design margins for HPHT wells are smaller and there are more stringent requirements for material selection [10].

1.3.4 Casing Architecture

The complexity of wells has increased over the past decades as wells being drilled in greater water depths and to deeper targets. Drilling margin (high PP relative to FG) can be considered as the main driving force for the well complexity. This often implies that casing strings needs to be upsized and set deeper, wellhead hanger system modified and new generation of casing tools used [11].

Casing architecture can be divided in two groups:

- *Typical* or so-called *normal-clearance architecture:* this design is commonly used worldwide where drilling margins are high. The following figure illustrates typical design (modified from [11]):

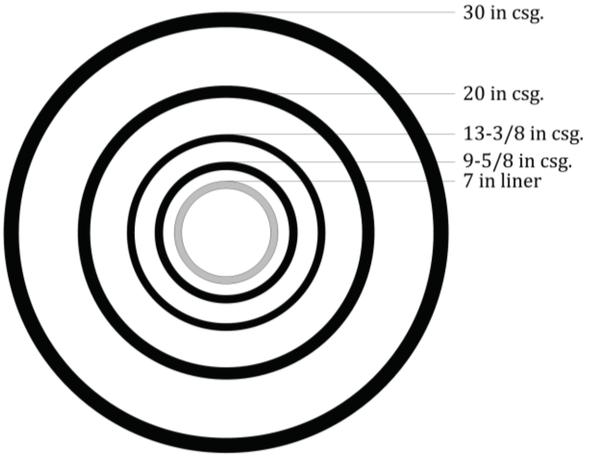

Figure 1-1: Normal-clearance Casing Architecture

- *Tight-clearance architecture:* this design increases number of strings available, hence minimizing the need of major changes to the rig and subsea equipment. The following figure illustrates one of design alternatives (modified from [11]):

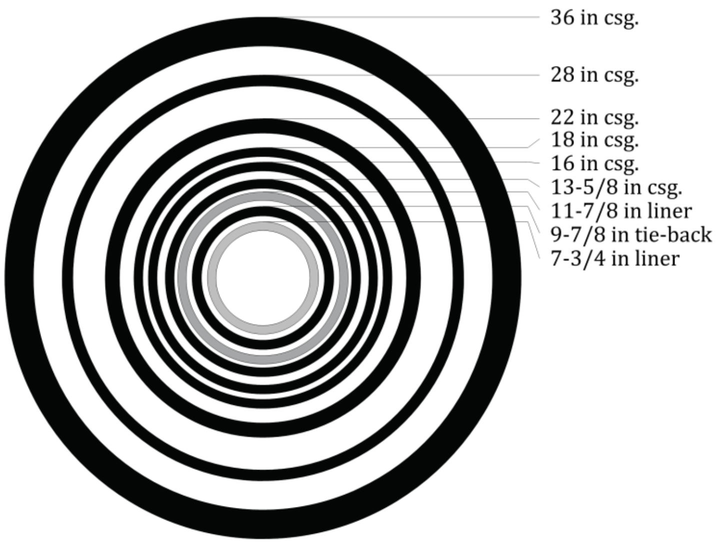

Figure 1-2: Tight-clearance Casing Architecture

Casing architecture will define the rig type and specifications for rotary table as casing will have to pass through it. Certain strength requirements will lead to increased casing wall thickness. This will affect effective flow area in the annulus and result in reduced clearance between couplings and previous casing. Therefore coupling configuration will always be a governing factor when it comes to casing clearances and hence casing architecture [10].

1.3.5 Casing Design

Health and Safety Executive in the United Kingdom (UK) has developed Operational Guidance [18] that lists several requirements that are applicable for well design:

- Well shall be designed to prevent blowouts and any unplanned release of fluids.
- Casing programme shall also include for all identified sub-surface hazards, ref. upcoming Section 1.3.9.
- Casing strings should withstand worst conditions for burst and normal conditions for collapse and tensional loads.
- Casing material shall also account for fluids that casing is expected to be exposed to.

Although these requirements are formally in force in the UK, they can be used as criteria for a well design elsewhere in the World.

In order to comply with the above, among others, it is important to choose correct setting depth for each casing string. It is therefore recommended to thoroughly evaluate the following aspects of the design [10]:

- Hole stability and curvature
- Subsurface pressure and integrity
- Drilling fluids, hole cleaning and cementing precautions
- Mechanical equipment planned for operations
- Overall economy

Suggested casing shoe setting depth evaluation process is presented in the following figure [10]:

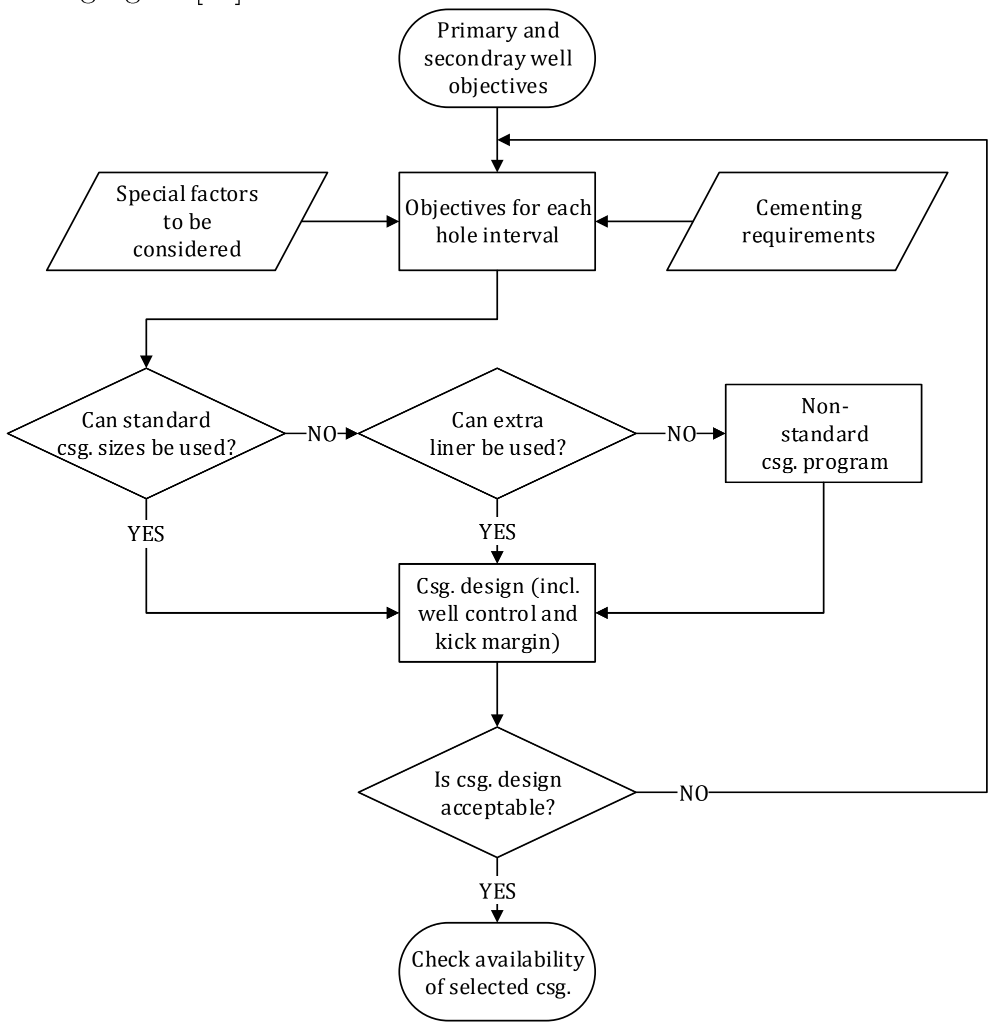

Figure 1-3: Casing Shoe Setting Depth Evaluation Process

PP and FG are the two most important parameters when evaluating setting depth of casing strings. The evaluation can be performed either by considering mud weight or kick criteria. Regardless of the analysis method, casing seats are determined from the reservoir, or Target Depth (TD), and 'working' upwards [10].

Mud weight consideration [10]: In this method, one starts close to the PP curve and draws vertical lines until the intersection with the FG curve. Each intersection of the drawn line with the FG curve indicates casing seat depth. In order to allow for some uncertainty in FG curve or for operational conditions (e.g. Equivalent Circulating Density (ECD)) one might stop drawing the line prior to intersection with FG curve. The approach is schematically illustrated in the following figure:

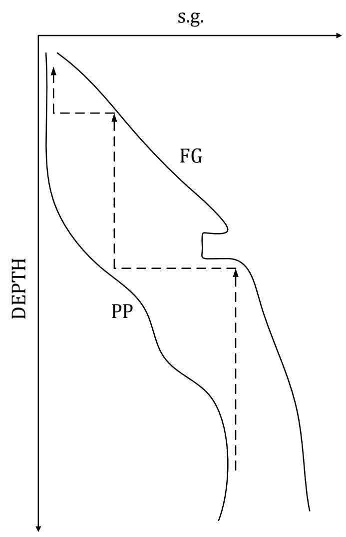

Figure 1-4: Casing Seats Determined by Mud Weight Criteria

Consideration shall be given when well is to be drilled from floater, as one need to include for so-called 'riser margin' [10]. Riser margin is hydrostatic head that represents difference between the mud column in the riser and the pressure of surrounding seawater [17]. Riser margin (additional head) is obtained by increasing drilling mud density and is required to balance pore pressure at the drilling depth in case of emergency disconnect situation. The minimum mud weight can be calculated with the following equation [10]:

$$\rho_{mud} = \frac{PP \times D - \rho_{sw} \times h_{sw}}{D - h_{air} - h_{sw}} \tag{1}$$

Where: D is TVD from Rotary Kelly Bushing (RKB) to drilling depth; ρ_{sw} is density of seawater; h_{sw} is height of seawater column (from water surface to mudline); h_{air} is 'air gap' between RKB and water surface.

Kick control consideration [10]: In this method, PP and FG curves are converted and represented as pressures. One starts close to the PP curve and draws expected formation fluid gradient line, until the intersection with the FG curve. Each intersection of the drawn line with FG curve indicates casing setting depth. The approach is schematically illustrated in the following figure:

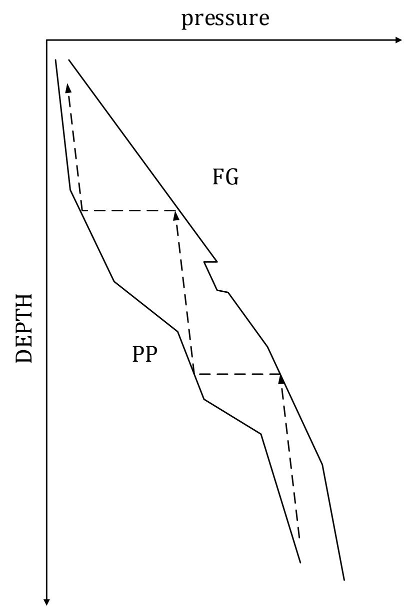

Figure 1-5: Casing Seats Determined by Kick Control Criteria

It is observed that casing seats are placed deeper in this case compared to the other method. Such long strings are unfavourable due to overall cost; therefore, the concept of reduced well integrity is introduced. According to this concept, all casings but the production casing may be designed for reduced integrity, provided that the casings must not burst. This means that in case of a kick, formation below the casing shoe must be the weakest point. For all casings that are designed according to this concept, maximum allowable kick size must be calculated.

Selection of design criteria for casing strings is regarded as the most critical activity in the well design phase. It is therefore important to establish the most realistic scenario for each casing section, where all relevant criteria shall be used in the analysis. Casing design involves strength assessment of the string w.r.t. burst, collapse and tensional loads [10]:

- *Burst.* The following main criterions can describe most of the cases that lead to casing burst:
  - *Gas-filled casing.* This criterion assumes that the well is fully filled with gas or formation fluid and then shut-in. Balancing pressures on the inside and outside of the casing yield in highest-pressure difference right below the wellhead. This criterion is mostly applied for the production casing.
  - *Leaking tubing.* This criterion assumes that there is a leak into the A-annulus (compartment between production tubing and production casing) just below the wellhead during production or well testing. The leak will superimpose pressure onto the completion fluid between the production casing and production tubing and will result in the excessive pressure at the production packer elevation.
  - *Maximum gas kick.* This criterion is based on the largest gas influx volume that can be handled without fracturing the formation at the last casing shoe. This criterion is commonly used to calculate acceptable kick volumes for the non-production casing strings.
- *Collapse.* The following main criterions can describe most of the cases that lead to casing collapse:
  - *Mud losses to a thief zone.* This criterion is based on the fluid loss inside the casing into formation. The pressure gradient outside the casing remains the same and hence causes collapse.
  - *Collapse during cementing.* This criterion is based on wet (not set) cement behind the casing. The scenario will result in high outside pressure at the bottom of the casing. The higher the cement column the higher the pressure difference will be.
- *Tensional loads.* If casing is exposed to axial loads that are higher than material strength, tension failure will occur and the casing will part.

Once strength assessment has been performed, the results shall be derated for different operational aspects according to the analysis scenario chosen. The most common aspects are:

- Downhole temperature
- Bi-axial/Tri-axial loading
- Sour/Sweet services
- Time scenario
- Casing wear

Additionally, pre-defined safety factors for different scenarios shall be met.

1.3.6 Drilling Fluid Selection

In offshore drilling on NCS, it is common to drill two first sections with no returns to surface. Cuttings are dumped to seabed some distance from the well. Those sections are therefore drilled with seawater with some additives that are not harmful to sea environment. Depending on lithology, next two sections might be drilled with either Water Based Mud (WBM) or Oil Based Mud (OBM). The reservoir section is always drilled with OBM [19].

Another important parameter of drilling fluid is mud weight. It was observed that when mud weigh is maintained close to the in-situ subsurface stresses, most of the borehole stability problems were minimised. It was later shown that [10]:

- When mud weight is equal to the horizontal stress the surround rock will be undisturbed by the drilling activity.
- When mud weight is lower than horizontal stress the stress will locally change and will cause borehole to decrease in diameter. This will ultimately cause tight hole and borehole collapse.
- When mud weight is higher than horizontal stress, pressure will tend to increase borehole diameter that will ultimately result in formation fracturing.

Consequently, design methodology called ‘median line principle’ was derived, the aim of which is to minimise disturbance on the borehole wall [10].

1.3.7 Borehole Cleaning

Poor borehole cleaning is one of the contributing factors that increases NPT when drilling the well. Proper mud and casing design plays important role in achieving good results, especially for deviated and long reach wells. Specialized flow simulators are usually used to determine optimal mud and drilling parameters when establishing a drilling programme [10].

1.3.8 Drillstring Design and Bit Selection

Profound knowledge of well objectives and drilling operations is required when designing a drill string. A drill string shall serve the following basic functions [20]:

- Transmit and support axial loads
- Transmit and support torsional loads
- Transmit hydraulics

Specialised torque and drag simulators are commonly used to determine optimal design of both casing and drill strings.

Bit selection to a great extent will depend on the lithology in the area and the Bottom Hole Assembly (BHA) used. One would typically use roller-cone bits in the upper sections. Poly-Diamond Crystalline (PDC) bits are commonly used in the lower sections or together with rotary steerable assemblies.

1.3.9 Hazards

Incidents, in drilling operations, can be categorised as following [21]:

- Mechanical equipment failure
- Organizational issues (operational judgement errors)
- Geo-drilling hazards:
  - *Over pressurised zones* that originate from brines or HC
  - *Depleted zones* result in low pressure intervals
  - *Mobile formations* lead to increased torque
  - *Faults* give a rise to hole instability
  - *Abrasive formations* wear out drilling bit
  - *Boulders* may deflect the well trajectory
  - *Shallow gas pockets* may result in well control problems
  - *Gas hydrates* may result in variety of outcomes, ranging from collapsed tubing [22] to worst case gas blow-out [23]
  - *Hydrogen sulphide* occurrences would likely result in equipment failure

Although there is not that much that can be done with organizational issues (apart from better planning), technical and geo-drilling hazards can be assessed and mitigated using as low as reasonably possible principle.

1.3.10 Cementing

Since the introduction of cementing activity to the well drilling in the beginning of 19th century, the main objecting of cementing was to provide zonal isolation and thus exclude fluid transfer from one zone to another.

Evolution of the subject yielded in more profound understanding and effects of the cement on the drilled and cased well. Cementing jobs in well drilling operations can be categorized as following [24]:

- Primary cementing
- Remedial cementing
    - Squeeze cementing
    - Plug cementing

Primary cementing plays important role in well construction phase. As name implies, primary cementing refers to first instance of cement placement in annulus between the formation and the casing. Cementing job must therefore be planned and executed given sufficient consideration. Adequate casing centralization is a prerequisite for successful primary cementing job, as this affects not only the well construction cost but also further maintenance, logging and abandonment activities.

Nowadays a hydraulic seal between the formation and a casing string is a requirement. Therefore, all casing strings up to reservoir are being cemented.

The cement seal not only provide isolation towards production zone but also provides corrosion protection and supports the casing strings [25].

The main purpose of cement behind the different casing strings is different and is detailed in the following [24]:

- Conductor csg. - prevent formation erosion.
- Surface csg. - protect water zones and support deeper casing strings.
- Intermediate csg. - isolate/seal abnormally pressurized zones and incompetent formations.
- Production csg. - prevent migration of fluids in the annulus and provide zonal isolation.

Minimum casing cement length requirement for different sections as well as initial verification methods are detailed in the NORSOK Standard D-010, Table 22 [17].

Remedial cementing is used to improve primary cementing job, repair casing leaks and to isolate productive formations to name a few.

1.3.11 Logging

While the first downhole temperature measurement was performed in 1869, it was not until 1927 when the first experimental electric log was recorded. Since then logging was mainly used to locate permeable formations [26].

There is a variety of logging tools, techniques and methods. Logs are also used differently by different disciplines. From a well construction point of view the most valuable logs are the ones that describe the formation (log results affect well architecture and design) and cement quality (log results affect well construction progress, maintenance and abandonment activities).

Many wireline logs depend on good bonding between the cement and casing and cement and formation, therefore insufficient bonding will produce erroneous results and may result in misinterpretation of the data. Another aspect of insufficient cement bonding is crossflow between the different pressure zones. In worst case, crossflow can lead to uncontrolled HC escape to surface. It is therefore important to obtain and correctly interpret logs of the cement jobs.

Temperature log was the first log that was used to evaluate Top of Cement (TOC) column. Nuclear materials were sometimes added to the cement to facilitate identification of TOC by means gamma-ray log. The cement job quality was mainly evaluated by means of hydraulic testing. Acoustic and temperature logs were and are still commonly used to verify crossflow between formations [24].

The most common logs for cement verification are combination of Cement Bond Log (CBL) and Variable Density Log (VDL).

Despite today's advancement in logging technology, logging tools are struggling in obtaining reliable data behind the thick production casing wall [27]. This important factor shall be evaluated in the well design phase.

1.3.12 Well Completions

Completions are arrangements of various equipment and tubulars that provide connection of subsurface reservoir with surface and thus means of safe HC production. In order to achieve optimal production from a well, completion options shall be considered in the early well design phase. Similarly as to the casing design, it is recommended to design completions from bottom and up.

- Completions are divided into two main groups: Lower (reservoir) completion and Upper completion [28, 29].

Lower completion provides production or injection control and can be further divided into:

- Open hole completions
  - Stand-alone screens
  - Open hole gravel pack
  - Barefoot completion
  - Predrilled and slotted liner
- Cased and perforated completions
  - With sand control
  - Without sand control

Upper completion, in turn, provides well control and may consist of the following components:

- Tail pipe
- Polished bore receptacle
- Production packer
- Formation isolation valve
- Control lines
- Chemical injection valve
- Pressure and temperature gauges
- Circulation devices
- Production tubing
- Packer fluid
- Gas lift mandrels
- Annular safety valve
- Downhole safety valve
- Production tubing hanger
- Christmas tree (XMT)

2 Well Abandonment

2.1 Historical Overview

There is limited historical information available on well abandonment activities outside the United States of America (USA). However, considering the fact that the USA was one of the countries pioneering oil discovery and production, it is natural to presume that the information representative for the USA is comparable to other countries in the World timewise.

Early oil exploration focused on only one objective - find oil. Health, safety and environment perspective was non-existent and there were no regulations governing well construction, oil production and well abandonment throughout the 18th century. When 'drilled' wells were dry or producing wells would stop production, the wells were abandoned by throwing in whatsoever debris at hand into the well. Many wells were even left unmarked.

First rules concerning Plug and Abandonment (P&A) were introduced in the eastern states of the USA in 1890's and were focused on protection of oil bearing zones from invasion of fresh water.

There was a discrepancy of applied practices and rules in force in different states until rules started to be unified by different bodies starting from 1920's. Specific cementing instructions were introduced in 1934 and isolation of fresh water zones has become a requirement from 1957. However, even then, the major consideration was to lower the cost of 'lift' that would be introduced by water entry into the wellbore.

Regulations introduced in early 1970's described in detail placement techniques and location for placement of P&A plugs and the tests required in order to prove constructed isolation. The tools considered in the P&A activities were cement, casing, mechanical plugs and mud. Completion design served as a basis for P&A design where completions could be partially removed to suit the zonal isolation needs [4].

Although drilling for oil on continental Europe begun in 18th century, the extent of exploration was limited compared to the USA. Major discoveries seemed improbable and extensive offshore exploration didn't begun until 1950's [30]. It is therefore believed that P&A technology applicable for the early well abandonment was 'imported' from abroad and local development of rules was almost non-existent. Offshore exploration and development after 1950's has however contributed to the involvement of local governments and regulatory bodies into further development of existing Laws and rules.

Nowadays different countries has own set of rules and guidelines regarding the well abandonment activities. While local nuances are inevitable in terms of barrier details, they all share the same common idea and requirements [31]:

- Isolate and protect all freshwater zones.
- Isolate all potential future commercial zones.
- Prevent leaks from and into the well.
- Cut casings to an agreed level below mudline and remove all subsea/surface equipment

It will be further focused on Rules and Regulations in Norway and United Kingdom (UK) due to advancement, amount of details and constant work on the documents detailing the P&A activities.

2.2 Rules and Regulations in Norway

Petroleum activities in Norway were initially regulated through the Continental Shelf Act of 1963. The Continental Shelf Act was later replaced by Petroleum Act in 1985, which was further revised in 1997 [32]. The Petroleum Safety Authority Norway (PSA) is responsible for development of regulations and guidelines that accompany Petroleum Act. PSA is an independent governmental regulator body that also enforces developed regulations on NCS.

Among others, regulations refer directly to the Norwegian petroleum industry (NORSOK) Standard D-010 that had its initial issue in 1997. The NORSOK Standards, in general, indicate the requirements that needs to be strictly followed and from which no deviation is permitted [17].

The Petroleum Act of 1997 and the obligations of the Oslo-Paris (OSPAR) Convention regulate todays decommissioning activities on the NCS [32].

2.2.1 NORSOK Standard D-010 (2013)

The NORSOK Standard D-010 concerns well integrity in drilling and well operations. In its initial issue the Standard only had a minor subsection dealing with well abandonment. The section was called ‘Cement Plug as a barrier’ and detailed length of the plug for three distinct cases and two testing methods [33].

Since then, the Standard went through several revision rounds. Fourth revision of the Standard is currently in force and was last updated in 2013.

Opposed to the initial issue, the current revision has the whole chapter devoted to the abandonment activities [17].

The important concepts of *well integrity*, *well barrier schematics*, *requirements for well barrier* and *well abandonment* are presented in the following.

2.2.1.1 Well Integrity

Well integrity is defined as "*application if technical, operational and organisational solutions to reduce risk of uncontrolled release of formation and well fluids to the surface and subsurface throughout the life cycle of the well*". The integrity of the well shall be assured at any stage of the well life cycle. Thereby well barriers must be defined prior to commencement of any activity on the well and, consequently, implemented and adhered to through the execution of the activity. *Well Barrier* (WB) is defined as an envelope of several Well Barrier Elements (WBE) that prevents unintentional fluid flow from the formation into the wellbore, to surface or to another formation. *WBE* is in turn defined as a physical element that on its own cannot prevent fluid flow from its one side to another [17].

2.2.1.2 Well Barrier Schematic

Well Barrier Schematic (WBS) is a graphical representation of the barriers visualised on the well schematic. WBS will typically address/contain the following information [17]:

- Drawing illustrating current primary and secondary well barriers.
- Formation integrity for the cases when formation is a part of WB.
- Reservoir and/or potential sources of inflow.
- Tabulated listings of WBEs along with their initial verification and monitoring requirements.
- All casings and cement sections. Size, depth (TVD and Measured Depth (MD)) and TOC should be labelled when casings and/or cement are defined as WBE.
- Position of well components that are indicated correctly in relation to each other.
- General well information such as well name, status, approvals and date is also present.
- Clear labelling of WB status: *as built* or *planned*.
- Any failed WBE must be clearly stated.
- Field for additional notes on well integrity information.

The following figure visualises example of primary (blue colour) and secondary (red colour) barriers of the platform well that is capable of flowing to surface (modified from [17]):

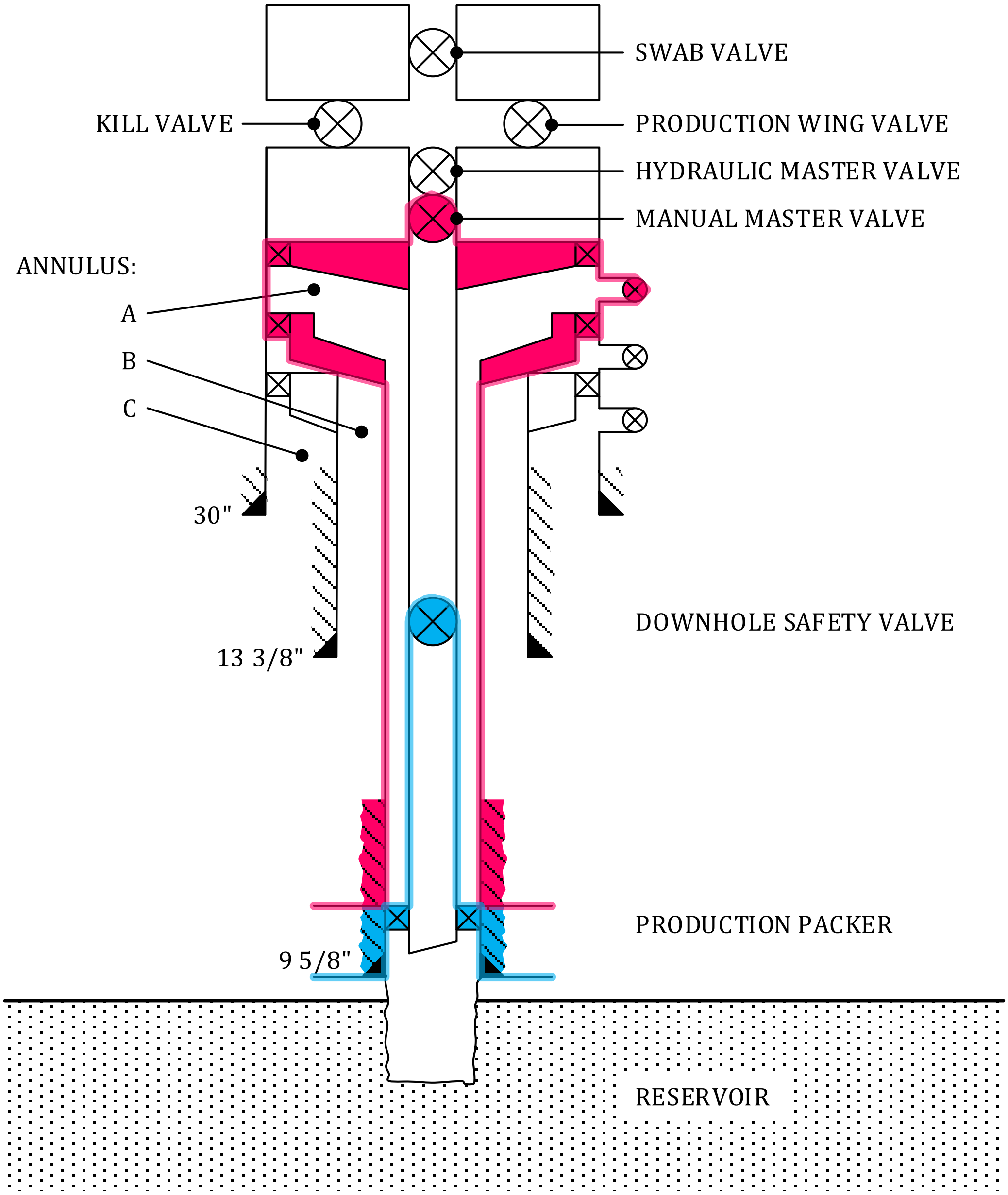

Figure 2-1: Primary and Secondary Barriers of Platform Well

2.2.1.3 Well Barrier Requirements

Necessity of well barriers is dictated by subsurface lithology and formation content. Minimum number of required well barriers is summarized in the following [17]:

Two well barriers are required for:

- HC bearing formations
- Abnormally pressurized formations that have potential to flow

One well barrier is required for:

- Abnormally pressurized HC formation with no potential to flow
- Normally pressurized formation with no HC and no potential to flow
- Prevention of undesirable cross-flow between formations

Among other requirements, well barriers shall be designed to withstand maximum differential pressure and temperature it may be exposed to during the lifetime of the well.

Two independent well barriers are commonly required during the operations. However, in some cases well barriers may share the same well barrier element. Such WBE is called *Common Well Barrier Element* (CWBE) [17]. The following figure illustrates cement plug inside the casing that is CWBE (modified from [17]); note that casing cement has been verified as two separate WBEs:

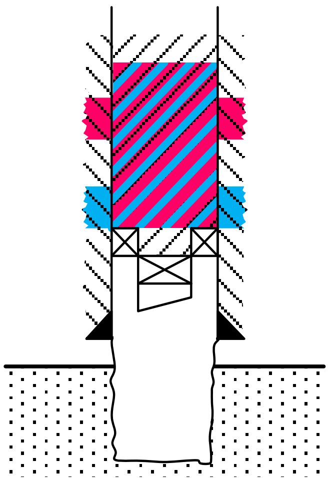

Figure 2-2: Cement Plug as Common Well Barrier Element

After WBE has been installed, its integrity shall always be verified either by pressure test or by other specific test methods (e.g. weight load).

2.2.1.4 Well Abandonment

Well abandonment activities that are covered by the Standard can be grouped as following [17]:

- Suspension of well activities
- Temporary well abandonment
  - Temporary well abandonment with well monitoring
  - Temporary well abandonment without well monitoring
- Permanent well abandonment
- Permanent abandonment of well section

Suspension of well activities

Suspension is defined as a well status, where all well activities are suspended while well control equipment is left in place. This definition can apply to wells under construction or intervention. Examples of root causes for the suspension can be bad weather, personnel strike, skidding of cantilever to perform work on another well to name a few. It is a requirement that WBE materials shall have sufficient integrity for the whole suspension period including some contingency. It is important to note that well suspension is the only abandonment activity that allows fluid column to be used a primary barrier.

Temporary well abandonment

Definition of *temporary well abandonment with well monitoring* is applicable to the wells where both primary and secondary barriers can be monitored and routinely tested. Monitoring and testing of WBEs shall be performed according to the relevant Element Acceptance Criteria (EAC) tables. There is no maximum abandonment period for such wells according to the Standard.

Subsea wells in which barriers cannot be monitored can be categorised as *temporary well abandonment without well monitoring*. A program of visual monitoring is required to be developed for such wells, where frequency of monitoring is dictated by the specific risk assessment but shall not exceed one year. WBE materials shall have sufficient integrity for the whole abandonment period. The maximum abandonment period shall not exceed three years.

It shall be noted that according to the Activities Regulation, Section 88: Securing Wells, exploration wells commenced after 01.01.2014 shall not be temporarily abandoned beyond two years. Additionally, in production wells abandoned after 01.01.2014, HC-bearing zones shall be P&A permanently within three years if the well is not continuously monitored [34].

Prior to temporary abandonment, plans for the well shall be documented and the following completion components shall be pressure/function tested:

- Production/injection packer
- Tubing hanger
- Tubing
- Downhole Safety Valve (DHSV)
- XMT valves
- Tubing hanger crown plugs in case of Horizontal XMT (HXMT)

All valves shall have zero leaks or plugs shall be installed to compensate for this.

There is also a requirement that it should be possible to safely re-enter the well during the whole abandonment period.

Permanent well abandonment

Permanent abandonment is defined as a well status, where the well is not intended to be used or re-entered again. Well shall be P&A with an eternal perspective taking into consideration foreseeable chemical and geological processes as well as formation pressure recharge. The definition of eternity, is however, not specified by the Standard. All sources of inflow shall be identified and documented and hence make a basis for barrier design. The following well barrier name convention is used in the P&A activities:

- Primary barrier - isolates source of inflow from surface and is indicated by blue colour.
- Secondary barrier - functions as back-up for the primary barrier and is indicated by red colour.
- Crossflow barrier - prevents undesired fluid flow between formations and can function as primary barrier for reservoir below.

- Open hole (or environmental) barrier - isolates flow conduits left in hole from surface after casing strings are cut and retrieved.

It shall be noted that base of primary, secondary and crossflow well barriers shall be placed at depth, where formation integrity will be higher than potential pressure caused by fluid at barrier base.

The following figure visualises example of permanent abandonment of a multi-reservoir well (modified from [17]):

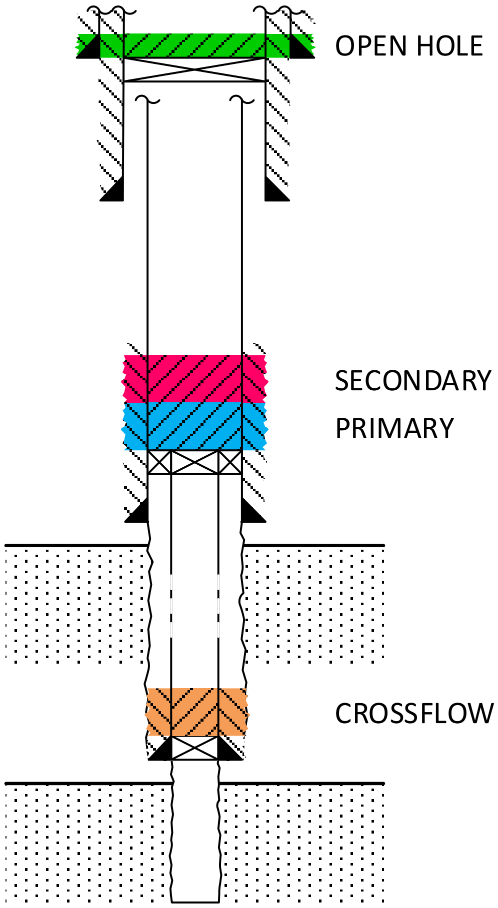

Figure 2-3: Permanent Abandonment of a Multi-reservoir Well

The following shall be as minimum considered in the permanent well abandonment design [17]:

- Permanent WB shall extend across full cross section of the well (including all annuli) and seal both vertically and horizontally.

- Permanent WB shall be placed adjacent to impermeable formation that has sufficient integrity to withstand potential pressure below.
- Permanent WB can function as shared well barrier in multilateral wells.
- Overburden formations and shallow sources of inflow.
- Multiple reservoir zones having the same pressure gradient can be regarded as one reservoir.
- Suitability of plugging material(s) shall be verified and documented. Such material(s) should have the following characteristics:
  - Provide long term integrity
  - Impermeable
  - Non-shrinking
  - Able to withstand mechanical loads
  - Resistant to subsurface chemicals, sour and sweet gases and HC
  - Provide good boning to steel
  - Not impair steel tubular integrity
- Downhole equipment, control line(s) and cable(s) shall be removed.
- Elastomer materials are not acceptable in WBE.
- If completion tubular is to be left in the well and plugging material is to be placed across it, the material inside completion tubular shall verified by tagging and pressure test, while material outside the completion tubular shall only be verified by pressure test.
- Wellhead and casings shall be removed below the mudline to the depth that ensures no stick up in the future.
- Consideration shall also be given, but not limited to, the following EAC tables:
  - EAC Table 2 - Casing
  - EAC Table 22 - Casing Cement
  - EAC Table 24 - Cement Plug
  - EAC Table 25 - Completion String
  - EAC Table 51 - In-Situ Formation
  - EAC Table 52 - Creeping Formation
  - EAC Table 55 - Material Plug
  - EAC Table 56 - Casing Bonding Material

Additionally, for casing cement and plugging materials to be qualified as WBE they must meet the following minimum length and verification requirements [17]:

- Casing cement:

  - o 50 m MD when verified by displacement calculations.
  - o 30 m MD when verified by cement bond logs.
  - o Sealing ability of casing cement is verified by formation integrity test after the casing shoe has been drilled out.
- Plugging materials in open hole:
  - o 100 m MD with minimum 50 m above source of inflow.
  - o Plug in transition from open hole to casing shall extend at least 50 m MD above and below casing shoe.
  - o Plugging materials in open hole shall be verified by tagging only.
- Plugging materials in cased hole:
  - o 50 m MD when set on mechanical foundation (e.g. bridge plug).
  - o 100 m MD otherwise.
  - o Plugging materials in cased hole shall be verified by tagging and pressure test. Only tagging is required for plugs that are set on foundations that were pressure tested. Pressure test can be performed in both directions. For pressure test performed in downward direction the following parameters shall apply:
    - ▪ 70 bar (1000 psi) above leak off pressure below casing or potential leak path or
    - ▪ 35 bar for environmental plugs

NOTE: Pressure tests shall account for casing strength and wear.

- For combination or back-to-back barriers in both open and cased holes criteria are the same, but barrier lengths are doubled.

Permanent abandonment of well section

This abandonment type is valid for the wells that are to be sidetracked. Original wellbore should be permanently abandoned prior to sidetrack according to the principles for permanent well abandonment described above. If permanent abandonment is deemed unfeasible at the time of sidetrack, permanent abandonment shall be done when the slot is to be permanently abandoned.

2.3 Rules and Regulations in the United Kingdom

Petroleum activities in the United Kingdom (UK) were initially regulated through the Petroleum Act of 1918. The Petroleum Act was first updated in 1934 and more recently, together with some elements from Continental

Shelf Act of 1964, was consolidated into the Petroleum Act of 1998. This Act, among others, contain rules that relate to decommissioning of offshore installations.

Decommissioning of onshore wells is addressed through the Integrated Pollution Prevention and Control legislation and permission for decommissioning is required from the Department of Trade & Industry according to the Petroleum Regulations of 1995.

Offshore wells, in turn, has to be abandoned according to the Oil & Gas UK Guidelines for the Suspension and Abandonment of Wells [32].

2.3.1 Guidelines for Abandonment of Wells (2015)

Initial issue of the document was published in 1994 and since then went through five revision rounds. As the name implies 'Guidelines for the Abandonment of Wells' provide guidelines on how to abandon a well in what is to date considered being a safe manner. Unlike NORSOK Standards, the guidelines have a suggestive character.

Although the guidelines are written by the UK offshore industry, the principles outlined in the documents are also valid for the onshore wells.

The guidelines are focusing on explaining the *requirements for well barriers* and *well abandonment* as well as verification of these [35].

2.3.1.1 Phases of Well Abandonment and P&A Code System

Guidelines offer classification of well abandonment phases according to the well section abandoned and provide classification codes that describe complexity of the outstanding activities for each phase.

Phases of Well Abandonment

- Abandonment Phase 1 - well can be classified as abandoned to Phase 1 when all producing or injecting zones are fully isolated from the wellbore.
- Abandonment Phase 2 - requires that all intermediate zones above the reservoir(s) are fully isolated (zones with flow potential). The Phase 2 is complete when no further permanent barriers are required.
- Abandonment Phase 3 - is concerned with severing wellhead, conductor and casing strings a few meters below seabed.

According to the regulations valid in the UK sector of North Sea, wells abandoned to the Phase 1 and 2 require physical inspection. Inspection schemes for such wells are subject of special risk assessments. No physical inspections or monitoring is further required once the well has been abandoned to Phase 3.

P&A Code System

P&A code system is based on a two-letter and three-digit code that is detailed in the following figure:

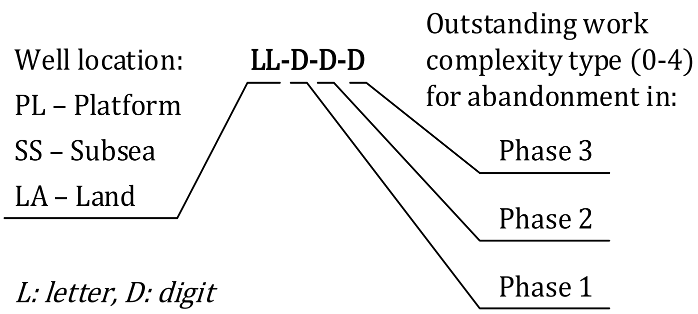

Figure 2-4: P&A Code System

Outstanding work complexity types are defined as following:

- Type 0 - no work is required (work may already have been completed).
- Type 1 - simple rigless abandonment using wireline, pumping, crane (well intervention vessels without a riser are used for subsea wells).
- Type 2 - complex rigless abandonment using coiled tubing or workover unit (well intervention vessels with riser are used for subsea wells).
- Type 3 - simple rig based abandonment that require retrieval of tubing or casing.
- Type 4 - complex rig based abandonment that will typically require milling and cement repairs.

It is further referred to *Guidelines on Well Abandonment Cost Estimation* that detail how to determine well abandonment complexity type based on the presented classification.

The classification promotes standardised way referring to the wells being abandoned and provides means of easy communication between different disciplines.

Currently, inclusion of P&A barrier schematics in drilling program is sought after by the industry [36]. Including such well abandonment codes into the well schematics could improve understanding of well barriers. Additionally, classification allows for easy and efficient planning of well abandonment activities not only for the specific field but also for the multi-well abandonment campaigns.

2.3.1.2 Well Barrier Requirements

Similarly to NORSOK Standard D-010, minimum number of well barriers required (that is presented in the Guidelines) is based on the zones with flow potential and hence is the same as in D-010.

Guidelines are, however, emphasizing that evidence of flow potential may only become apparent during abandonments operation and hence precautions are required for adequate pressure control during such operations.

2.3.1.3 Well Abandonment

Guidelines do not clearly distinguish well abandonment into temporary or permanent as NORSOK Standard D-010. However, guidelines indicate that phase 1 and 2 abandonment must be carried out in such way that would allow safe well re-entry without compromising well barriers already in place.

Although methodology of well abandonment presented in the Guidelines coincides with the one described in D-010, small deviations exists. Some of the deviations are detailed in the following:

- Suitability of plugging material(s) shall be verified and documented according to the *Guidelines on Qualification of Materials for the Abandonment of Wells*. Latest revision of the document (Second edition, 2015) defines a testing criteria for plugging materials being one million days (~3000 years) [37]. Such material(s) should have the following characteristics:
  - Have very low permeability - prevent flow through the bulk material.
  - Provide an internal seal - prevent flow around the barrier.
  - Barrier must remain at the intended position in the well.
  - Provide long-term integrity.
  - Be resistance to downhole fluids at foreseeable pressures and temperatures.
  - Mechanical properties shall be suitable to accommodate loads at foreseeable pressures and temperatures.
- Removal of downhole equipment is not required, if isolations are achieved.

- Control line(s) and cable(s) shall, however, be removed.
- As the gasses and salt may impair cement used to plug the well, emphasis on wells containing hydrogen sulphide, carbon dioxide, Magnesium salts and high Gas to Oil Ratios (GOR) is made.

The following length and verification requirements for plugging materials are recommended:

- Casing cement:
    - 100 ft (~30.5 m) MD of good cement.
    - 1000 ft (~305 m) MD if based on displacement calculations or monitored differential pressure. This cement length can be regarded as two separate or a combination barrier.
    - Sealing ability of casing cement may be verified by leak off test after the casing shoe has been drilled out or by pressure test.
- Plugging materials in open hole:
    - 100 ft (~30.5 m) MD of good cement, where possible 500 ft (~152 m) shall be set.
    - It is additionally required to set a permanent barrier in the cased hole: 100 ft (~30 m) MD of good cement, where possible 500 ft (~152 m) shall be set.
    - Plugging materials in open hole shall be verified by tagging and weight test:
        - On drillpipe - 10 to 15klbs (4.5 - 6.8 ton)
        - On wireline, coiled tubing or stringer - weight is limited by tools
- Plugging materials in cased hole:
    - 100 ft (~30 m) MD of good cement, where possible 500 ft (~152 m) shall be set.
    - 100 ft (~30 m) MD of good cement must be assured for liner laps, otherwise liner laps are not acceptable as a permanent barrier.
    - Plugging materials in cased hole shall be verified by tagging and pressure test. The pressure shall be 500 psi above the expected pressure at the base of the barrier.

NOTE: Pressure tests shall account for casing strength and wear.

- For combination or back-to-back barriers in both open and cased holes 200 ft (~61 m) MD of good cement, where possible 800 ft (~244 m) are set.

2.4 P&A Considerations and Practices

In the following general approaches and P&A challenges of well abandonment operations are presented.

2.4.1 P&A Operational Sequence

P&A campaign/project can be divided into two distinct stages [38]:

- Preparations and inspection of the well
- P&A of the well (execution)

Preparations and inspection of the well

When planning P&A operation one would typically gather historical data about the well, such as: well and well barrier schematics, previous abandonment activities (if any), installation and maintenance records for XMT and tubulars, performed pressure tests, tools that are required for safe well access, cement logs, lithology and subsurface fluid data and information about any potential hazards [35].

Depending on XMT type (vertical or horizontal) different preparatory activities shall be performed before the P&A activity. The following figure schematically visualises main differences between two XMT types:

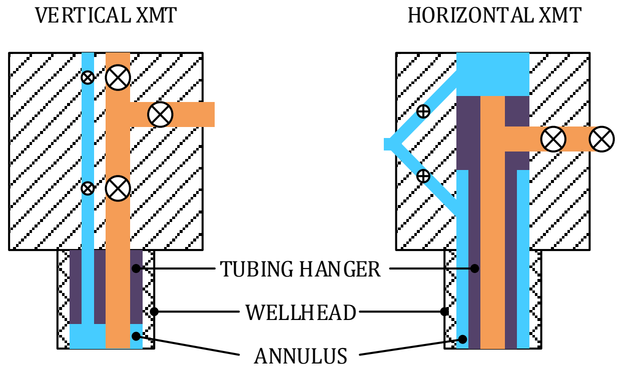

Figure 2-5: Vertical vs. Horizontal XMT

Should the obtained data indicate that tubing removal is necessary it is clear that in case of vertical XMT, the XMT needs be removed first (as tubing hanger is located in wellhead). This is not always a straightforward task as one need to decommission flowline and remove flowline spool/jumper and any control umbilical. Before vertical XMT is removed, one would install deep mechanical bridge plug and/or displace the well to kill mud and install shallow mechanical bridge plug. The task of pulling tubing is more easily achievable with horizontal XMT as one can install Blowout Preventer (BOP) directly on top of the horizontal XMT, install deep mechanical bridge plug, displace the well to kill mud and then pull the tubing. Based on the above one can presume that horizontal XMT is more beneficial for P&A activities.

Vessels are typically used in the offshore part of preparations stage, where: template/XMT are cleaned from marine growth; depending on XMT type and decommissioning sequence - flowline spool can be disconnected; XMT and DHSV valves are functioned [38].

Before arrival of drilling rig, vessels can additionally perform the following preparatory activities: well can be entered and killed, deep-set bridge plug can be installed, removal of vertical XMT, tubing punched and A-annulus fluid displaced to brine and finally tubing can be cut [39, 40]. Utilisation of vessel to perform these activities will minimise the overall cost of the P&A campaign [40].

P&A of the well

As described earlier, P&A of the well can be divided into three phases [35]. Due to uniqueness of distinct wells, there can be several alternatives to abandon the well. The generalised summary for each phase is presented below [40]:

- *Abandonment of reservoir section (Phase 1).* Drilling rig will be mobilized to location. Operation will then proceed depending on the extent of preparatory work performed by vessel (as described above). Today's technology do not allow logging behind two casing strings. For this reason, it may become necessary to remove tubing/casing in order to be able to log (verify) annular cement. Another common reason for pulling the tubing is presence of control lines, which are not permitted to be a part of the permanent well barrier. If well is equipped with vertical XMT, tubing hanger plugs must be installed before XMT can be nippled down and BOP nippled up. If horizontal XMT is used, BOP can be installed right on top. Tubing (together with lower completion) can be now pulled out. Logging of annular cement can commence once tubing has been pulled out.

  It is advised to perform logging of annular cement on all old wells. It is also advised to run nuclear magnetic resonance log tool to acquire additional data of the formations which might help in identification of possible zones of influx that were not identified during initial logging run [41].

If annular cement is of poor quality, one shall consider section milling. With today's technology, this operation can turn out to be time consuming and impose Health, Safety and Environment (HSE) risks as large quantities of swarf are produced [42]. However, the new technology that is based on plasma generation is being developed. This technology allows tiny steel particles to be formed during the 'milling' run. As opposed to swarf, generated particles will sediment. Additionally, plasma generation tool can be run on wireline from a vessel. Full scale offshore system trials are planned to be performed in North Sea by 2017 [43].

If no annular cement is present at planned barrier depth, one might consider using recently developed and efficient Perforate, Wash and Cement (PWC) technology.

The system based on PWC technology has excellent track record and allows for multi-casing as well as internal plug to be cemented in one operation, whereby significantly reducing operational time required to place the barrier across whole cross-section of the well [44].

If quality of annular cement is good, one can readily place cement plug inside the casing.

- *Abandonment of intermediate section (Phase 2).* Depending on zones to be sealed off, it might be sufficient to place casing plugs only. In case no annular cement is present at intended barrier elevation one might plan for section milling or use PWC technology. In some instances, pulling of tubing will be required in order to set cross-section barrier. Once all intermediate section plugs are set and tested, drilling rig can be released.

  Environmental barriers can easily be installed by Light Well Intervention Vessels (LWIV). Utilising such vessels in P&A operations (on NCS) has great potential of reducing overall P&A cost, as day rates for such vessels are much lower compared to drilling rigs.

  It shall be noted that abandonment of intermediate section in suitable wells can also be transferred to vessel, as required technology has already been developed [45].

- *Removal of conductor and wellhead (Phase 3).* Once surface barrier has been set and verified, severance of conductor/casings can commence. There are several ways to severe casings:
  - For the last decade, severance of casings with abrasive water jet cutting has gained popularity when it comes to subsea wells. The method is efficient and environmentally friendly [46]. In addition, equipment can be deployed from simple vessels that do not have PSA's Acknowledgement of Compliance (AOC) thus reducing the cost of P&A campaign.
  - Casings can also be severed with mechanical tools. Mechanical casing cutting tools are typically run on a drill string, thus requiring expensive rigs to operate.
  - Use of explosive charges in P&A operations is not common due to environmental and HSE issues.

2.4.2 P&A Challenges

It might be straightforward to P&A newly drilled exploration, appraisal wells or even some old wells, however P&A activity is commonly associated with great cost and many challenges. Challenges relevant for NCS are presented in the following [31, 47-52]:

As mentioned in the foregoing, each P&A campaign begins with acquisition/gathering of available data. When time came to abandon 'early' wells, it turned out that operator companies lack useful documentation from well construction phase (e.g. cementing and drilling activities). This is especially the case for wells which ownership has been transferred from one operator company to another. Lack of operational data makes it impossible to cross-check and difficult to evaluate old logs and thus requiring complete investigation of well status. This is time and resource consuming task.

Poor quality of primary cementing job might result in Sustained Casing Pressure (SCP) or allow for undisturbed crossflow between formations. While it is easier to detect SCP, it takes time to identify crossflow between formations. When developed, both situations will increase abandonment cost of the well.

It is not always easy to foresee post-abandonment reservoir pressure, therefore complications might arise developing and qualifying plugging material/cement with required strength that will seal efficiently for eternity.

Principles of basic well logging have not changed much in the past decades, but logging tools did. However, even with today's advancement in technology it might be difficult to qualify annular cement. The inability to log through two casing and obtain meaningful data when thick walled casing is present calls for tubing and casing removal and milling operation, whereby increasing cost and complexity of abandonment campaign.

Moving formations along with compaction and subsidence of overburden (due to production) present great challenges for both abandonment activities and in ensuring leak free well post abandonment. Moving formations will typically make wellbore inaccessible below the deformed casing, access to which would require a drilling operation. Compaction and subsidence does not stop once production has ceased, it will continue for some time to come. Permanent well barriers placed in such fields might develop leaks and will thus call for re-abandonment activities.

Formations with high permeability may hinder correct placement of cross-sectional barriers and potentially delay operation.

Abandoning high temperature reservoirs might be challenging as cement slurry might start setting too early (on the way down) hence compromising plug setting operation.

Development of extended reach and deviated wells is undoubted a good thing from production point of view. However, abandonment of such wells might require additional effort especially in cases when tubing/casing must be retrieved. Retrieval of long tubulars would require adequate lifting capacity due to weight and generated friction.

Abandonment operation will require a drilling rig for wells that do not have annular cement at the locations where the new overburden knowledge may dictate one and wells that have incompatible completion equipment or control lines.

Section milling is considered being unpopular activity during P&A. Milling operation can be time consuming; may lead to BHA failure, poor hole cleaning and pack-offs. Swarf handling onshore and offshore represents another challenge.

Examples of P&A challenges presented above indicate that sound engineering and P&A thinking is required when designing the well in order to minimise operations and hence cost of upcoming P&A activities.

3 Possible P&A Considerations in Well Design Stage

3.1 Subsurface Lithology

NORSOK Standard D-010 requires that *“all sources of inflow shall be identified and documented”* [17]. This requirement provides a good basis for environmentally friendly design of permanent well barriers. Isolation of all identified sources of inflow separately could result in high P&A cost [53]. Appropriate engineering judgement is therefore required to satisfy both legal and cost aspects of P&A operation. In order to came-up with the best solution all zones with potential must be first identified, what is not always an easy task.

Recently, DNV GL has released risk-based well abandonment guideline the objective of which is to provide risk-based framework for qualification of well abandonment design and permanent abandonment. The guideline emphasise importance of identification of zones with flow potential as these are the main building blocks and form the basis for risk-based well abandonment design together with evaluation of valued ecosystem components and dispersion modelling [54].

In order to map all potential zones, Statoil has previously initiated project for evaluation of flow potential in the overburden called “Overburden Management Project”. One of the projects objectives was to describe a work process/procedure of identification of flow potential in low permeability or impermeable zones in subsurface. The main findings of the project were [41]:

- It is difficult to define cut-off value for flow potential, as affecting factors such as permeability, pressure, subsurface volume/boundaries, fluid types, temperature and time are interrelated.
- Additional data acquisition is commonly required to provide a better picture of the subsurface, as zones with possible flow are not always manifested on standard logs.
- Sensitivity study of HC volumes in place revealed that flow potential would vary with varying reservoir size and fluid composition. However, subsurface evaluation in terms of geometry and lateral extent is challenging.
- It is recommended to perform identification of zones with flow potential during the whole life cycle of the well.

The workflow of identification of flow potential proposed is briefly summarised in the following [41]:

In the *Exploration Phase*, one should:

- Search for existing general data (NPD plays, near-field observations and datasets from offset wells.
- Plan data acquisition program and crosscheck standard data acquisition against earlier findings.
- Adjust data acquisition to observations during drilling.
- All observations must be reported - presence/absence/uncertainties of possible zones with flow potential.

In the *Field Development Phase*, one should:

- Extent search for additional existing data and involve other disciplines as appropriate.
- Initiate dedicated studies based on existing data if deemed necessary.
- Propose strategy for field data acquisition.

In the *Development Drilling Phase*, one should:

- Implement data acquisition strategy defined in previous phase.
- Assess newly acquired data from drilling and production and revise the existing data acquisition strategy.
- Identify the need for additional dedicated data acquisition.
- Ensure continuous documentation of findings.

In the *P&A Phase*, one should:

- Update existing P&A planning (well, concept, strategy) based on findings from the drilling and production phase.
- Consider the need of additional data acquisition during P&A.
- Include newly acquired data in future drilling and P&A panning.

It is also recommended to extend standard data acquisition by including Nuclear Magnetic Resonance (NMR) logging and pressure/inflow testing (seismic and laboratory testing can be included/evaluated) in data acquisition programme [41].

NMR logging is essentially electrical measurement that is sensitive to the quantity of free hydrogen protons that occur uniquely in the fluids/liquids. NMR technology have seen a spark and a broader use after the new concept called “inside-out NMR” was invented in 1980’s. The concept is based on the placement of two permanent dipole magnets in a certain way to attain radial magnetic field. Such tool is capable of generating magnetic field that is 1000 times the Earth's and can be easily combined with other logging tools. The tool can be used both in Logging While Drilling (LWD) and in wireline operations. "Inside-out NMR" allows for better porosity measurements and prediction of permeability through various empirical transforms. The log is typically presented as T_2 distribution, which is a representation of transverse relaxation time that is related to the dephasing of nuclear spins of hydrogen [55].

The following figure presents idealised interpretation of T_2 distributions for water-wet clastic rock (modified from [55]):

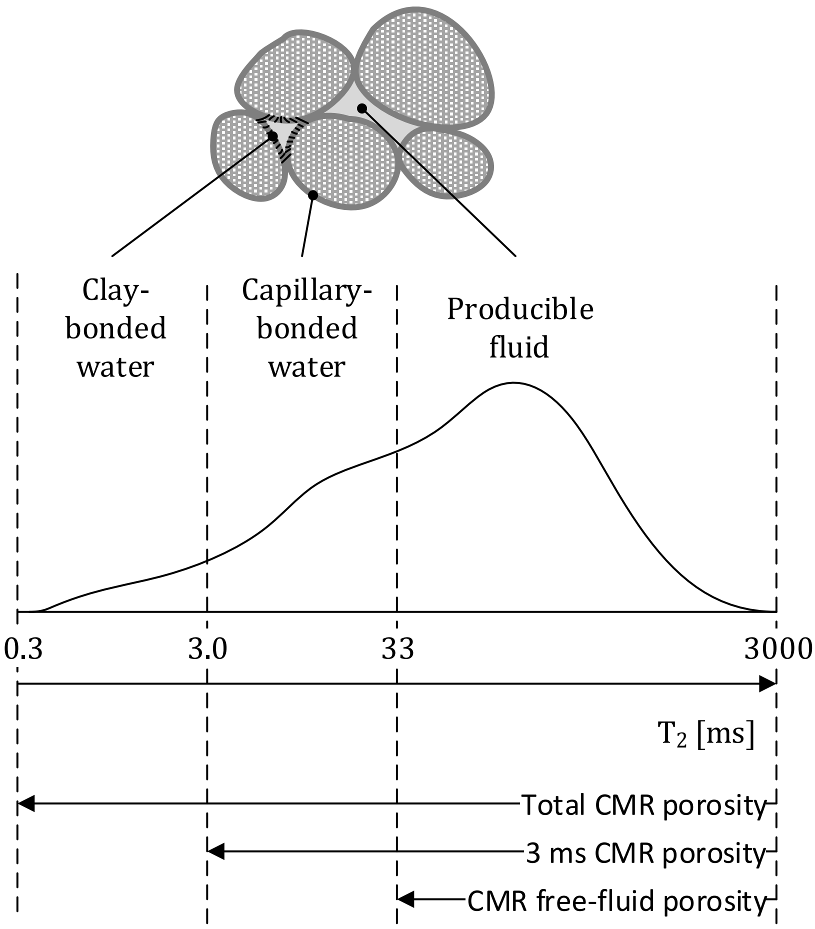

Figure 3-1: Interpretation of T_2 Distribution

It should be noted that neutron porosity tends to overestimate the actual porosity in shales, as the log is sensitive to hydroxyls in clay minerals, while density porosity and Combinable Magnetic Resonance (CMR) logs have quite similar pattern. However, CMR log will show deficiency of porosity in gas and tar zones. Those zones can hence be easily identified when CMR log is compared with either neutron or density porosity logs [55].

3.2 Primary Cementing

Poor quality of annular cement leads to milling and/or PWC operations during the P&A stage, which are both costly and time consuming. For this reason, well-planned and executed primary cementing job is important in order to avoid these challenges. PSA urges industry to increase focus on P&A when planning and drilling new wells. In particular, attention shall be given to improve primary cementing [56]. This is not without reason. Experience shows that mechanical and other properties of cement placed behind the casing are crucial for well to perform as intended throughout its life cycle thereby also contributing in attainment of low well abandonment cost [57].

Many experimental studies have been conducted in recent decades with focus on optimization of cementing operations. The common conclusion for these is that the success of primary cementing is based on obtainment of detailed well information and utilising the cement that is optimised for the particular wellbore [57-60].

Hydration of American Petroleum Institute (API) cement produces mainly calcium-silicate-hydrate phases and portlandite. Calcium-silicate-hydrate is responsible for strength of cement, while portlandite is considered being a weak element within the cement matrix. Increase of cement permeability and portlandite content results in decreased cement strength and resistance to corrosive environment. Experiments on cement cores have shown that addition of pozzolanic materials (siliceous and silica-aluminous materials) eliminate portlandite and lower water content in the cement systems. This improves mechanical properties of cement and reduces its permeability. As a result, significant reduction in cement corrosion is observed [61].

3.2.1 Cement Corrosion

Cement corrosion can be described as disintegration of set cement (components and structure) mainly due to attack of reactive fluids and/or gases. Cement corrosion can be caused by several mechanisms [24, 61]:

- High temperature. When cement temperature is higher than 110 °C, calcium-silicate-hydrate phases will transform into more stable phase that has high crystalline density. The later phase has reduced compressive strength and increased permeability in set cement. The latter reaction can be prevented when silica flour is added to a cement (30-40 % by weight).

- Expansive attack. Corrosive fluid containing sulphates or magnesium will enter cement pores and form water insoluble products. Those products promote growth of crystals, which in turn increase cement pore pressure and result in cement cracks.
- Dissolving attack. Carbon dioxide gas, on another hand, will react and dissolve cement matrix through several chemical reactions. Last reaction in the chain will form calcium bicarbonate, which is soluble in water and hence can easily be leached out of the cement matrix.

Some studies have been performed with the aim to identify carbonation front propagation rate in set cement. Experimental results agree with field data and show that carbonation rate can be reduced with increased slurry salinity for the wells with temperatures of around 50 °C. The following equation was found to fit experimental data [58]:

$$Depth\ of\ CO_2\ alteration\ front\ [mm] = 0.016 \times \sqrt{days} \tag{2}$$

Other studies have focused on wells with temperatures in the range of 180-300 °C and high carbon dioxide concentrations. The performance of studied wells has dropped after some 15 years of service. The conclusion was that compressive strength of set cement was reduced and cement integrity was lost [58]. This shows that carbon dioxide resistant cement shall be planned for and used in such wells.

3.2.2 Cement and Temperature of Surroundings

Accurate subsurface temperature acquisition has proved to be important when designing cement for high temperature wells. It has been found that in some cases empirical equations were more accurate when compared to data obtained from simulator software or downhole circulation probes. When designing a slurry for HTHP well it is recommended to follow the below guidelines in order to obtain best cement slurry design [59]:

- Confirm measured depth, bottom hole temperature and desired slurry density.
- Calculate bottom hole circulating temperature.
- Calculate heat-up rates.

- Provide details for specimen testing when sending request to the lab.
- Obtain and use fresh sample of actual location water in all tests.
- Obtain and use mud sample from actual location in compatibility tests.

Cement used in HPHT well shall also be “gas tight” meaning that slurry exposed to gas should form an impermeable film that would prevent gas migration through the cement or along the cement-to-formation interface [59].

A study conducted in mayor HPHT field in UK sector confirmed that life-of-well events cause failure of set cement. It was found that the effect of change-out of mud with production fluid had greatest impact. An effort has been made to design a slurry to account for life-of-well effects. The aim was to reduce hydration shrinkage volume to 0 % and to increased cement elasticity. New recipe was designed and used on several new wells in the field. New recipe proved to be successful as no cement leaks were observed on the new wells [62].

Seabed and sub-seabed temperatures are also important when cementing conductor casing in deepwater environment. Temperatures below 0 °C are typical for such environments and shall be accounted for. Experiments have shown that when calcium chloride content in cement blend is increased from 0 to 2.85 % by weight, cement heat generation peak is moved forward and dormant period in cement hydration process is shortened. Software simulator showed good agreement with experimental data [60]. This effect allows accounting for low temperature of surroundings and provide confidence in result of primary cementing in terms of wait on cement time.

3.2.3 Cement Type

Full-scale experiments have been conducted on inclined steel tubulars to determine cement bond efficiency. Five test were performed where Dyckerhoff class G cement was used in two experiments and expandable cement was used in three experiments. The results showed that expandable cement had lower equivalent permeability (13 milli-Darcy) compared to Dyckerhoff class G cement (3 Darcy). Although it should be noted, that ambient temperatures during cement curing time were different: 90 °C for expandable cement and 10 °C for Dyckerhoff class G cement [63]. This gives an indication that expandable cements shall be considered for primary cementing operations, as they will most likely perform better as permanent well barrier element.

3.2.4 Cement Placement and Cementing

As pointed out earlier, the success of primary cementing is dependent on optimal cement design. However, placement technique and physical boundaries must also be considered. It is therefore recommended to [57, 59]:

- Evaluate and adjust casing centralization for each section. Minimum 70 % standoff is recommended.
- Circulate twice the casing volume and monitor mud properties and shaker for any cuttings being received.
- Use plugs to separate slurries. This will reduce potential of channelling inside the casing due to buoyancy. Slurries will also have a potential to be cleaner when arrived at casing shoe and hence performing a better cleaning job inside the annulus.
- Use cement slurry that has density of at least 1ppg greater than of mud. This allows for spacer design that fits between the densities of cement and mud and still allowing for acceptable viscosity range for achieving good mud removal. When margins allow, it is advisable to have cement slurry density that is approx. 10 % higher than of mud used to drill a section.
- Adjust spacer volume so that its length in the annulus is at least 300 m or approx. 10 min of pumping time. Simulating software can aid in choosing optimal volume and pumping rate.
- Pre-flush with sodium silicate system to improve cement-to-steel bond and to reduce permeability of calcium and magnesium containing formations [61].
- Reciprocate and rotate casing during placement operations. This will break gel-strength development and will allow for more effective cement placement and mud removal. It shall however be noted that some operators may not allow reciprocation due to fear of casing protrusion above wellhead if cement sets. In some instances, rotation may also be impaired by the casing locking mechanism. It is therefore important to plan for casing movement in well design phase if operator company permits reciprocation and rotation while cementing [24].

Most recent field tests suggest that use of casing vibratory tool can further optimise primary cementing operations. The casing vibratory tool causes oscillating load between the casing shoe and the wellbore obstructions, thereby enhancing installation process compared to running casings traditionally or applying rotation and using high-torque casings. Analysis of jobs performed with vibratory tool show that the casing running speed has increased by approx. 120 % compared to running casings traditionally and approx. 20% compared to running casings while rotating. Additionally, casing vibration promotes uniform flow of mud outside the casing. Quality of primary cementing job also improves as voids and channels in the cement decrease due to fluid pulsation and casing vibration [64].

Considering the foregoing in primary cementing operations will greatly reduce chance of cement-sheath failures.

3.3 Evaluation of Primary Cement Job

Qualitative evaluation of primary cement job shall involve more than bare evaluation of cement log. Information about slurry system as well as operational conditions shall always accompany such evaluations. It is important to recognize that cement shall always be evaluated based on the cement job objectives [24, 65]. Appropriate cement evaluation shall therefore be considered if annular cement of surface and/or intermediate casings is planned to be used as a barrier element(s) when P&A the well.

3.3.1 Specialty Cements

Specialty cements may require additional techniques and instrument calibration to verify sonic strength of a cement. However, care shall be taken even when evaluating cements based on such "baseline" calibration, as actual properties of cement in the well might be different to the ones instrument was calibrated for.

3.3.2 Pressure Testing

Different pressure test types can be used to evaluate integrity of casing and cement. Positive pressure test, for instance, evaluates the ability of plug that sits on top of the float equipment to seal as well as determines any leaks in casing string. This test is typically performed immediately after bumping the plug (e.g. when cement is not set in the shoe track) [65]. Performing such a test when cement has been set, will most likely result in micro annulus due to deboning of a cement [24].

Determination of hydraulic seal at the casing shoe is commonly verified by formation pressure testing and may be required by regulations [65]. The test is performed after cement has set and casing shoe has been drilled-out. The applied pressure in such case shall correspond to a pressure that will be applied below the casing shoe during the drilling of next section. Pressure decrease during hold period serves as an indicator of poor cement job and hence requiring evaluation of remedial cementing [24].

3.3.3 Evaluation by Logging

In addition to pressure testing, annular cement can be evaluated with different logging techniques. Qualification of annular seal is important not only for drilling of next section or for setting well into operation, but also when abandoning the well. Missing and inconsistent log data or absence of certain log type are contributing factors affecting qualification of annular cement as a part of permanent well barrier. These result in the need of cutting and pulling tubing (and casings) in order to 'enable' logging of desired section(s). The task of pulling tubulars is time-consuming and requires a drilling rig to perform. In order to overcome this challenge the emphasis on logging, with P&A in mind, shall be made during well construction phase.

Immediate use of temperature logs is limited to determination of TOC. Temperature log must be run in the window when cement is setting in order to register exothermal reaction. Unplanned flow in the annulus can also be assessed with temperature log, provided that such annular flow is sufficient to change the temperature of surroundings. Annular flow identification has therefore a time aspect. When annular flow is suspected, noise log shall additionally be run to supplement evaluation.

Annular cement can be evaluated with sonic or ultrasonic tools. Both methods have advantages and disadvantages.

The CBL-VDL sonic tools provide information about presence of cement, cement-to-pipe and cement-to-formation bonding. Interpretation of radial logs, however, does not provide complete answer about the hydraulic seal of cement. Indication about effectiveness of cement bond can be obtained by listening to the sound generated in annular cement and by measuring its temperature [24, 51]. When interpreting CBL-VDL logs it is assumed that cement thickness is constant and that cement strength is uniform throughout the logging interval [65]. Opposed to radial tools, segmented tools provide greater insight into the cement as azimuthal information is obtained. For instance, generated radial cement map allows for interpretation of liquid filled annular channel that is in contact with casing. Channels within the cement sheath and at the cement-to-formation interface can only be obtained with noise and temperature logs [66].

Ultrasonic tools provide information about the nature of materials behind the casing and have greater resolution both radially and vertically. Another benefit of such tools is that interpretation of logs obtained with ultrasound will not depend on acoustic properties of the cement [67]. Ultrasonic tool can be configured to emit sound waves at an angle to casing, allowing determination of a very lightweight cement [65]. In addition, ultrasonic tools provide casing inspection data such as casing radius and casing thickness. Successful interpretation of ultrasonic logs is based on correct selection of threshold values for gas and liquid/cement that are anticipated to be behind the casing [65, 67]. Examples from deepwater wells in Gulf of Mexico (GOM) illustrate that ultrasonic tool can be readily used to log staged foam cement behind the heavy wall casing (0.625”). The 0.675” thick casing is deemed to be the most difficult casing to log [67].

Utilising both logs has proved to be advantageous, as limitations of both technologies are compensated. For instance, pipe-to-pipe and pipe-to-formation contacts can be differentiated more easily; collar response is more visible and provides some information on quantity of cement at collar location; leaks in tie-backs can be differentiated [68].

Considering the following parameters might contribute to improved cement evaluation [24, 65, 67, 69]:

- Cement shall reach representative cured state before log is run; compressive strength at TOC shall be at least 250 psi (lab testing is necessary).
- Depending on cementing technique, it might be feasible to run bit and scraper prior to logging in order to clean the casings inner surface.
- Logs shall be run under zero applied wellhead pressure to ensure that repeat and main log passes are performed under the same conditions. However, coinciding logs cannot guaranty the accuracy.
- Main log and repeat section must be consistent.
- Determination of cement quality shall not be based on Bond Index (BI) alone, because good cement may be interpreted as bad. This is especially important in long cemented sections where pressure and temperature affect setting of the cement. It is important to remember that BI is different for lead and tail cements. It is hence recommended to compute BI section by section.

- Log interpretation shall always be performed in conjunction with operational data available from primary cementing job.

Interpretation of today's cement logs is still considered to be challenging. The verdict on cement sealing capability is based on individual judgement/experience. Logging tool calibration and actual downhole conditions affect logging data obtained and thus introduce additional uncertainty to the logs. Based on the above, cement bonding can rather be described with words depicting degree of (un-)certainty such as 'most likely', 'probably' or 'possibly' when evaluating a certain log [70].

3.4 Control Lines and Downhole Equipment

Depending on well objectives and expected operational conditions, lower and upper completion may be equipped with one or several completion components that require control line or a power cable to function or to acquire downhole data. Control (capillary) lines are typically used to provide actuation of hydraulic components such as sliding sleeve, formation isolation valve, annular safety valve and downhole safety valve. Control lines are also used to inject various chemicals downhole. Electrical lines are typically used to provide electrical power to submersible pump downhole. Electrical and fibre optical lines are used to transfer the data in both ways. Control lines and cables are commonly gathered into bundle and are encapsulated in plastic. This encapsulation/bundling ease installation (clamping onto the completion string), provide certain level of chemical resistance and reduce shock and vibrations. Downhole and operational conditions dictate what materials can be used to manufacture control lines and cables. Melt-processible thermoplastics such as fluorocopolymers are commonly used as encapsulation material. It should be noted that, although encapsulation materials generally have excellent resistance to oil/diesel and well fluids, the encapsulation material will soften and degrade with time when exposed to oils [28].

According to NORSOK Standard D-010, downhole equipment shall be removed if it can cause loss of integrity, whereby control lines and cables shall not be a part of permanent well barrier [17]. The requirement imply that design of 'smart' completions, placement of formation isolation valve and chemical injection valves shall be carefully picked. In 'smart' completions, control lines and cables are routed from reservoir section to surface/subsea. Consequently, such completions cannot be abandoned without extra effort.

Completion design of more simple wells, on another hand, can be adjusted to ease future P&A operations. Chemical injection valves are typically placed as close as possible to production packer [29] and are used to continuously inject chemicals in small quantities to mitigate formation of deposits on inner wall of the tubing. Mandrels, gauges and other valves are commonly placed above chemical injection valve(s) [28]. Placement of chemical injection valves and consequently control lines at shallower depth is beneficial from P&A point of view. This allows for placement of cross-sectional barriers above the packer without need of removing tubing, provided presence of competent annular cement behind production casing. However, placement of chemical injection valve(s) at a shallower depth will leave section of production tubing untreated. In order to minimise scale deposits in untreated section and below production packer certain coating systems may be considered [42]. Coating layer is usually very thin and depending on the vendor provide resistance to corrosion, erosion and accumulation of certain deposit types (such as asphaltene, paraffin and scale).

Recently, full-scale experiments have been conducted on inclined steel tubulars to determine cement bond efficiency where several tubing strings had control lines clamped to them. The study, among others, concludes that control lines did not present any additional leakage paths [63]. This study indicates that, indeed, one can possibly leave tubing in the well given that cement behind the production casing has been verified and there is no need for tubing removal to provide access to logging.

This brings-up a topic of inclusion of control line/cable bundles in the permanent well barrier.

Although control lines shall not be a part of permanent well barrier, they are in principle suitable for this purpose as they are typically made of alloy 825 or 316L materials. There is experience of plugging control lines on the NCS: Failure of formation isolation valve on one of the wells on Snorre field has resulted in direct communication of reservoir with surface through control lines. Production was ceased and both lines were plugged with specially developed resin mixture. This mixture was injected to approx. 1900 m below the wellhead in one line and to approx. 680 m below the wellhead in another. Control lines were then pressure and inflow tested. Plugging operation was deemed successful, as communication with reservoir was no longer present. Well continued to produce thereafter [71].

Encapsulation and fill material of electrical and optical lines would require rigorous qualifications as materials of cables/bundles are commonly designed to match the design life of well completions (typically 25 years). For instance, there is a documentation that direct failure of encapsulation material caused failure of control line to DHSV in GOM. Experimental testing confirmed that acidic environment was created inside the crevices created by cracked encapsulation. This is despite that material was designed to be utilised in rough environment [72].

3.5 Monitoring of B-Annulus

B-annulus is defined as compartment between production casing and previous casing string. Monitoring of B-annulus is required for gas lift and multi-purpose platform wells by NORSOK Standard D-010, whereby B-annulus for subsea wells shall be designed to withstand thermally induced pressure [17].

Monitoring of B-annulus is important from P&A point of view for two main reasons: SCP might indicate poor sealing of annular cement [62]; when production casing is to be partially removed any trapped pressure/gas might lead to a well control incident [42].

Technology to monitor B and C-annuli (C-annulus is the closest outer annular compartment to B-annulus) for exploration HPHT well has been already developed and successfully tested offshore. The system tested consisted of pressure and temperature gauges (two in each annulus: primary and back-up) along with transponder device clamped onto the casing below the wellhead on one end and transponder device clamped onto the drill pipe and connected by the cable to the topside computer on another end. B and C-annulus gauges were situated approx. 400-480 m below the wellhead and allowed for real-time pressure and temperature read-out by the transponder that was clamped on to the drill pipe and located above the BOP test tool. Communication link with all four gauges was established within approx. 5 min of deploying 'surface' transponder and continued throughout whole duration of BOP test. It was also possible to recover logged and stored readings from the gauges for previous operational phases, however slowness of data transfer limited complete data extraction within the duration of BOP test [73].

Technology utilising transponders alone is limited by battery time, therefore another approach is taken to monitor B-annulus in non-exploration wells. Roxar has developed an electronic wireless tool that can measure pressure and temperature in B-annulus. The system requires connection to the ¼" communication cable (either existing or dedicated) and consists of [74]:

- In A-annulus: primary antenna, annulus B reader gauge.
- In B-annulus: secondary antenna, annulus B transponder gauge.
- Controller card: that can be placed either in subsea electronic module or standalone canister.

This system was successfully installed on one of the subsea wells in the Skuld field (NCS) and has minimum expected lifetime of 20 years [75].

Another company, Techni, has also developed a solution for B-annulus monitoring. System consists of ultrasound transceiver for installation in A-annulus and the B-annulus device. B-annulus device consist of two passive oil filled measurement chambers (closed and open one). Ultrasound transceiver requires connection to the controller card that can be placed either in subsea electronic module or in standalone canister [76]. Unfortunately, no information is available about installation of such system offshore.

3.6 Example Case

This section provides theoretical example that briefly illustrates well design process in which consideration to future P&A activity is given.

Offshore Subsea Well

Background information: Water depth in the field is approx. 475 m. The field will be developed with three 4-slot subsea templates. Reservoir will be drained by means of pressure depletion. Hydrogen sulphide has not been identified; methane gas (0.19 s.g.) shall be considered in design process. TD is 4600 mTVD (RKB). Air gap is 25 m (RKB to MSL).

Immediate availability of the following casings has been confirmed (other types have lead-time and are available on request):

Casing size	Grade	Weight [lb/ft]	Burst strength [bar]
30 in.	X-56	310	-
18-5/8 in.	X-70	84.5	197
13-3/8 in.	X-70	72	510
9-5/8 in.	Q-125	53.5	854

Table 3-1: Available Casing Sizes

7” tubing and non-retrievable packer are planned for. Lower completion is not part of the analysis and hence is not detailed.

The following subsurface data has been provided for the analysis (anticipated permeable zones are indicated by letter ‘k’):

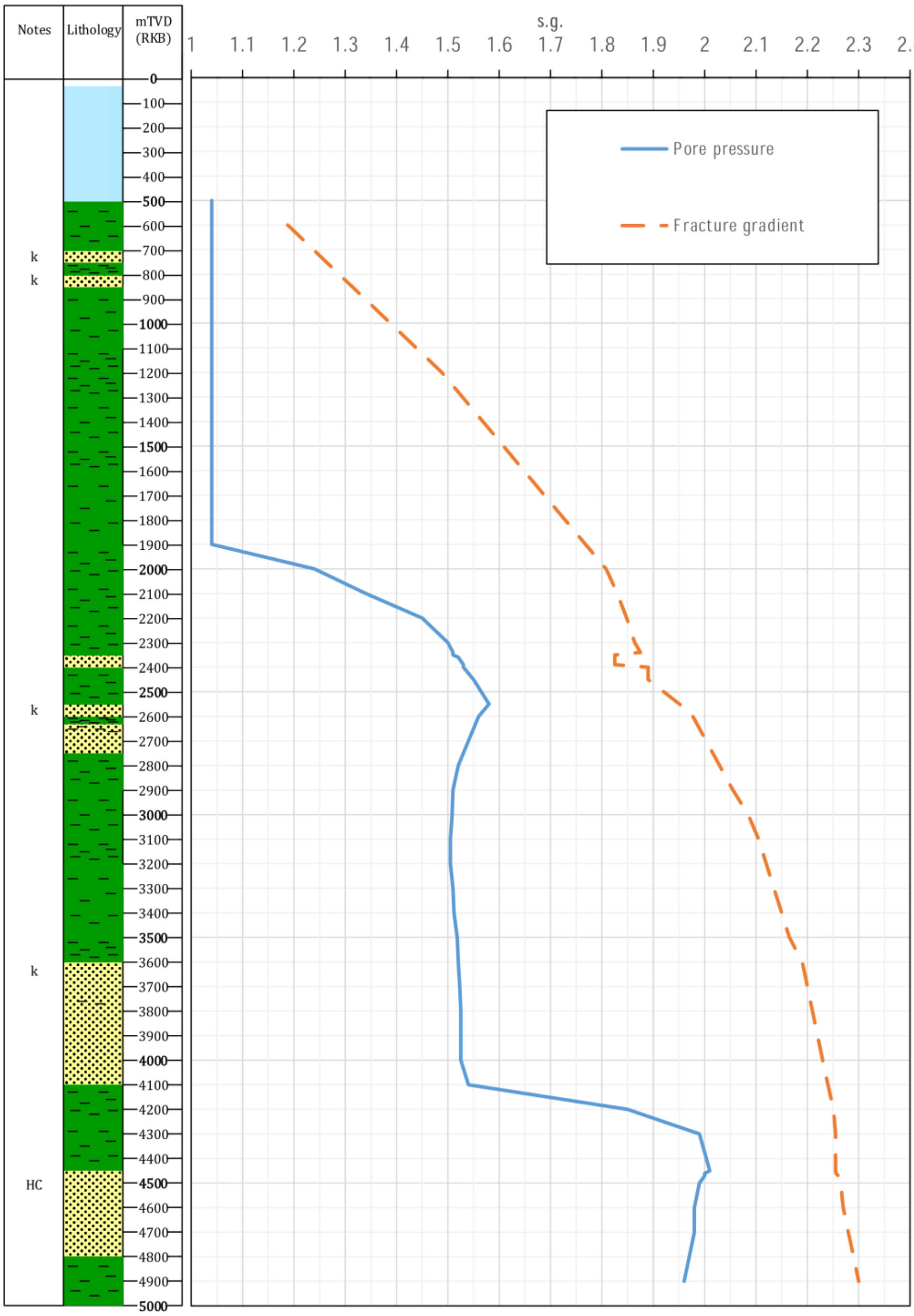

Figure 3-2: PP and FG Curves (Example)

Evaluation: Well will be drilled with semi-submersible drilling rig. Riser margin must be therefore included prior to further analysis, ref. Eqn. (1):

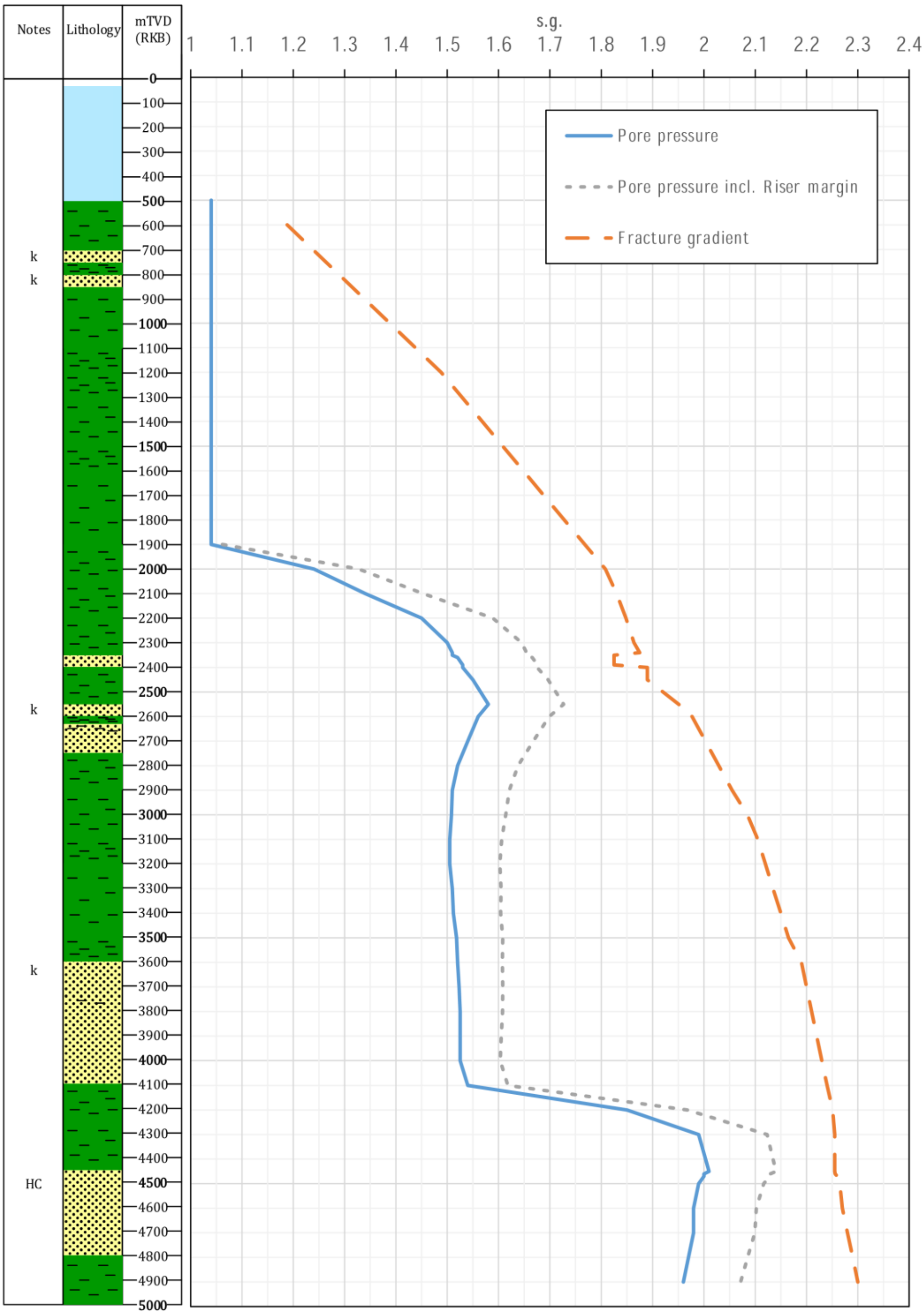

Figure 3-3: PP and FG Curves incl. Riser Margin (Example)

Casing seats can now be determined using mud weight as criteria (line with arrows); median mud line is also visualised:

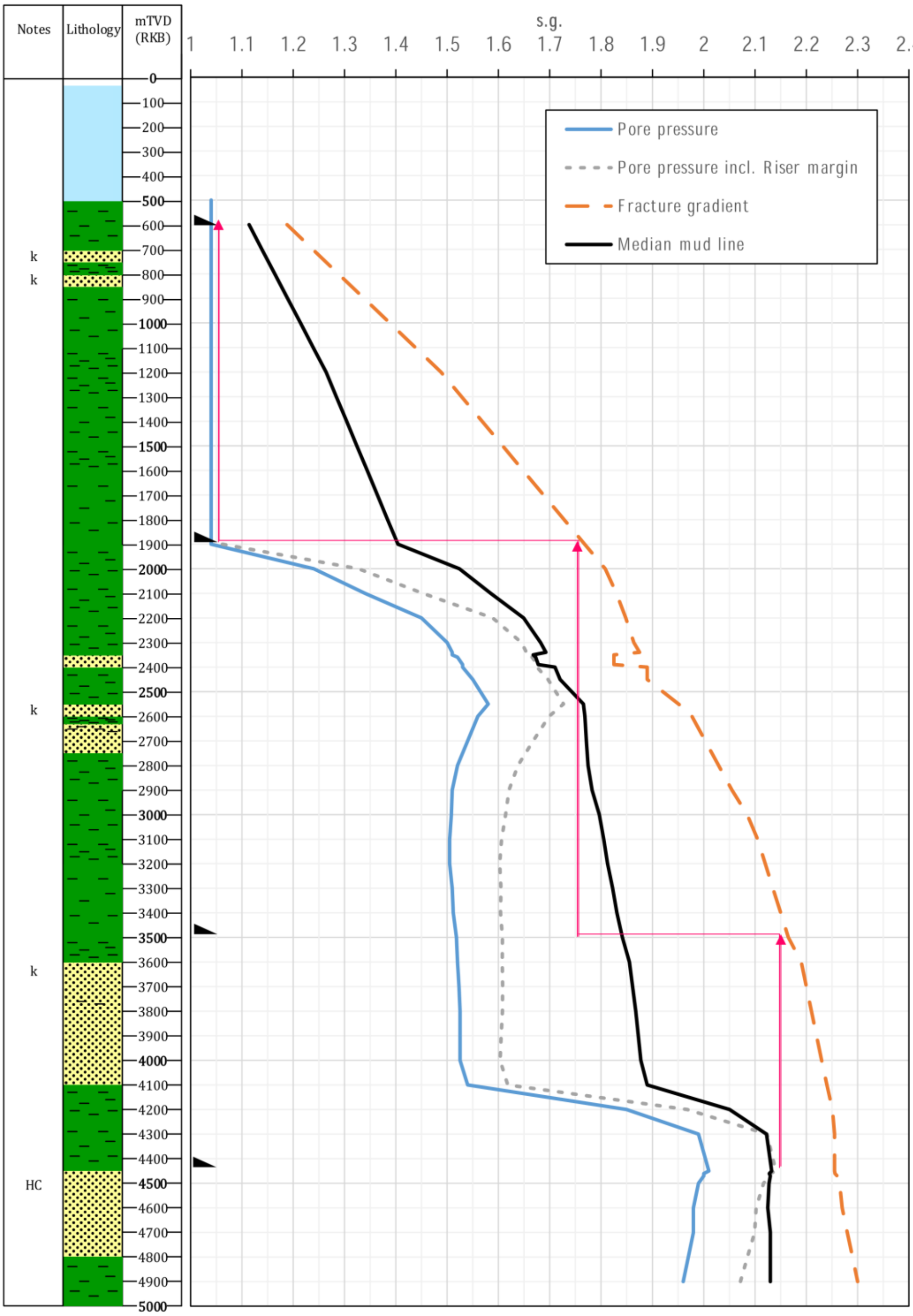

Figure 3-4: PP and FG Curves incl. Casing Seats (Example)

The first two sections will be drilled with seawater and without BOP. Cuttings will be deposited some distance from the well (using cuttings transport technology). Consequently, inclusion of riser margin is not needed for these sections.

In order to prevent surface blowout, it is important to ensure that casings below wellhead are designed to withstand pressure of gas-filled well (worst case). This is achieved by either implementing full or reduced well integrity concepts. For this reason, only burst loads will be analysed in the following. Burst analysis is based on the pressure balance between inside and the outside of the casing/tubing. Burst load has post-installation perspective (when next section is drilled). When analysing burst mode it is assumed that casing cement is set, particles are settled and that water is the only mobile phase behind the casing.

3.6.1 Well Design - Not Considering P&A

It shall be noted that some values presented in calculations below were rounded up when transferred from Excel, hence final results might deviate slightly when calculation is performed manually.

3.6.1.1 Conductor Casing

Conductor casing is planned to be set to 100 m below mudline (600 mTVD). Burst is not a concern for conductor casing due to 'open system' subsea when next section is drilled.

3.6.1.2 Surface Casing

Surface casing is planned to be set to 1400 m below mudline (1900 mTVD). Next section is planned to be drilled to 3000 m below mudline (3500 mTVD). Density of seawater is 1.04 s.g. and gravity acceleration is 9.8 m/s^2.

External pressures can be calculated first:

$$P_e \text{ @ } wellhead = 1.04 \times 0.098 \times 475 = 48.41 \ bar$$

$$P_e \text{ @ } shoe = 1.04 \times 0.098 \times 1875 = 191.10 \ bar$$

Pore pressure at the bottom of next open hole section is calculated next:

$$P_o = 1.52 \times 0.098 \times 3500 = 520.67 \ bar$$

Internal pressures are then calculated (assuming gas filled well):

$$P_i \ @ \ shoe = P_o - 0.19 \times 0.098 \times (3500 - 1900) = 490.88 \ bar$$

$$P_i \ @ \ wellhead = \ P_o - 0.19 \times 0.098 \times (3500 - 500) = 464.81 \ bar$$

Consequently, highest burst load at wellhead is equal to:

$$P_i \ @ \ wellhead - \ P_e \ @ \ wellhead = 464.81 - 48.41 = 416.40 \ bar$$

Burst strength of given 18-5/8 in. casing is de-rated by 10% for wear prior to further comparison:

$$P_{casing \ strength} = 197 \ \times 0.9 = 177.30 \ bar$$

When comparing de-rated burst strength of the casing and highest burst load at wellhead it becomes clear that casing would burst.

Consideration will be now given to well integrity aspect: If the well is filled with gas and shut-in, calculated earlier internal pressure at shoe will correspond to:

$$P_i \ @ \ shoe = \frac{490.88}{0.098 \times 1900} = 2.64 \ s.g.$$

Fracture gradient at shoe depth is $P_f \ @ \ shoe = 1.77 \ s.g.$ and hence underground blowout would occur in case of well control event. In order to avoid this, kick margin is introduced. Calculation of kick margin is outside the scope of this example.

The last thing to verify is that weakest point is at the shoe and not below the wellhead. Applying standard safety factor for burst ($SF_{burst} = 1.1$), maximum allowable pressure at wellhead is calculated:

$$P_{b \ MAX} \ @ \ WH = \frac{197}{1.1} = 179.09 \ bar$$

If the well is filled with gas and shut-in and the maximum allowable pressure at wellhead is 179.09 bar, then pressure at shoe is:

$$P_i \ @ \ shoe\_new = 179.09 + 0.19 \times 0.098 \times (1900 - 500) = 205.16 \ bar$$

This pressure corresponds to:

$$P_i \; @ \; shoe\_new = \frac{205.16}{0.098 \times 1900} = 1.10 \; s.g.$$

Clearly, this is not acceptable as the weakest point would be below the wellhead and casing would not withstand the pressure.

Several options exist to rectify this situation:

1) Place casing shoe at shallower depth: depth of 1200 mTVD has been identified to be suitable for given casing; P_i @ $shoe\_new = 1.63$ sg vs. P_f @ $shoe = 1.49$ $s.g.$
2) Choose casing with better burst strength: a 16 in. casing with P-110, 84 lb/ft and burst strength of 411 bar has been identified to be suitable for the purpose; P_i @ $shoe\_new = 2.15$ sg vs. P_f @ $shoe = 1.77$ $s.g.$ @ 1900 mTVD.

As a conclusion 16 in. casing detailed in alternative two above is a better option from drilling perspective, as one would try to set casings as deep as possible in order to obtain better margins when next section is drilled. Selected 16 in. casing represents reduced well integrity case, as it does not have required strength below the wellhead.

3.6.1.3 Intermediate Casing

Intermediate casing is planned to be set to 3000 m below mudline (3500 mTVD). Next section is planned to be drilled to 3950 m below mudline (4450 mTVD).

External pressures can be calculated first:

$$P_e \; @ \; wellhead = 1.04 \times 0.098 \times 475 = 48.41 \; bar$$

$$P_e \; @ \; shoe = 1.04 \times 0.098 \times 3475 = 354.17 \; bar$$

Pore pressure at the bottom of next open hole is calculated next:

$$P_o = 2.01 \times 0.098 \times 4450 = 876.56 \; bar$$

Internal pressures are then calculated (assuming gas filled well):

$$P_i \; @ \; shoe = P_o - 0.19 \times 0.098 \times (4450 - 3500) = 858.87 \; bar$$

$$P_i \text{ @ } wellhead = \; P_o - 0.19 \times 0.098 \times (4450 - 500) = 803.01 \; bar$$

Consequently, highest burst load at wellhead is equal to:

$$P_i \text{ @ } wellhead - \; P_e \text{ @ } wellhead = 803.01 - 48.41 = 754.60 \; bar$$

Burst strength of given 13-3/8 in. casing is de-rated by 10% for wear prior to further comparison:

$$P_{casing\ strength} = 510 \; \times 0.9 = 459.00 \; bar$$

When comparing de-rated burst strength of the casing and highest burst load at wellhead it becomes clear that casing would burst.

Consideration will be now given to well integrity aspect: If the well is filled with gas and shut-in, calculated earlier internal pressure at shoe will correspond to:

$$P_i \text{ @ } shoe = \frac{858.87}{0.098 \times 3500} = 2.50 \; s.g.$$

Fracture gradient at shoe depth is P_f @ $shoe = 2.17 \; s.g.$ and hence underground blowout would occur in case of well control event. In order to avoid this, kick margin is introduced. Calculation of kick margin is outside the scope of this example.

The last thing to verify is that weakest point is at the shoe and not below the wellhead. Applying standard safety factor for burst ($SF_{burst} = 1.1$), maximum allowable pressure at wellhead is calculated:

$$P_{b\ MAX} \text{ @ } WH = \frac{510}{1.1} = 463.64 \; bar$$

If the well is filled with gas and shut-in and the maximum allowable pressure at wellhead is 463.64 bar, then pressure at shoe is:

$$P_i \text{ @ } shoe\_new = 463.64 + 0.19 \times 0.098 \times (3500 - 500) = 519.50 \; bar$$

This pressure corresponds to:

$$P_i \text{ @ } shoe\_new = \frac{519.50}{0.098 \times 3500} = 1.51 \; s.g.$$

Clearly, this is not acceptable as the weakest point would be below the wellhead and casing would not withstand the pressure.

As with the surface casing, several options exist to rectify this situation:

1) Place casing shoe at shallower depth: depth of 2500 mTVD has been identified to be suitable for given casing; P_i @ $shoe\_new = 2.04\ sg$ vs. P_f @ $shoe = 1.92\ s.g.$; this would result in a section that is only 600 m long, which is undesired.
2) Choose casing with better burst strength: a 11-7/8 in. casing with LS-140, 65 lb/ft and burst strength of 767 bar has been identified to be suitable for the purpose; P_i @ $shoe\_new = 2.20\ sg$ vs. P_f @ $shoe = 2.17\ s.g.$ @ 1900 mTVD.

As a conclusion 11-7/8 in. casing detailed in alternative two above is suggested for the job. Selected 11-7/8 in. casing represents reduced well integrity case, as it does not have required strength below the wellhead.

3.6.1.4 Production Casing

Intermediate casing is planned to be set to 3950 m below mudline (4450 mTVD). Next section is planned to be drilled to 4100 m below mudline (4600 mTVD).

External pressures can be calculated first:

$$P_e \text{ @ } wellhead = 1.04 \times 0.098 \times 475 = 48.41\ bar$$

$$P_e \text{ @ } shoe = 1.04 \times 0.098 \times 4425 = 451.00\ bar$$

Pore pressure at the bottom of next open hole is calculated next:

$$P_o = 1.98 \times 0.098 \times 4600 = 892.58\ bar$$

Internal pressures are then calculated (assuming gas filled well):

$$P_i \text{ @ } shoe = P_o - 0.19 \times 0.098 \times (4600 - 4450) = 889.79\ bar$$

$$P_i \text{ @ } wellhead = \ P_o - 0.19 \times 0.098 \times (4600 - 500) = 816.24\ bar$$

Consequently, highest burst load at wellhead is equal to:

$$P_i \text{ @ } wellhead - \ P_e \text{ @ } wellhead = 816.24 - 48.41 = 767.83\ bar$$

Burst strength of given 9-5/8 in. casing is de-rated by 10% for wear prior to further comparison:

$$P_{casing\ strength} = 854\ \times 0.9 = 768.60\ bar$$

When comparing de-rated burst strength of the casing and highest burst load at wellhead it is observed that casing should withstand gas-filled scenario (0.75 bar margin).

Consideration will be now given to well integrity aspect: If the well is filled with gas and shut-in, calculated earlier internal pressure at shoe will correspond to:

$$P_i\ @\ shoe = \frac{889.79}{0.098 \times 4450} = 2.04\ s.g.$$

Fracture gradient at shoe depth is $P_f\ @\ shoe = 2.26\ s.g.$ and hence open hole below the shoe will handle gas-filled scenario. Consequently, we have full integrity for production casing (as per requirements of NORSOK Standard D-010).

Calculation of tubing leak criterion is outside the scope of this example.

3.6.1.5 Casing Program

Based on the foregoing casing evaluation and the minimum casing cement lengths required by the NORSOK Standard D-010, the following casing program is proposed:

Casing size	Grade	Weight [lb/ft]	Seat Depth [mTVD RKB]	Cement Length Above Shoe [m]
30 in.	X-56	310	600	To mudline
16 in.	P-110	84	1900	To mudline
11-7/8 in.	LS-140	65	3500	100
9-5/8 in.	Q-125	53.5	4450	200

Table 3-2: Casing Program - Not Considering P&A (Example)

Proposed casing program is visualised in the following figure:

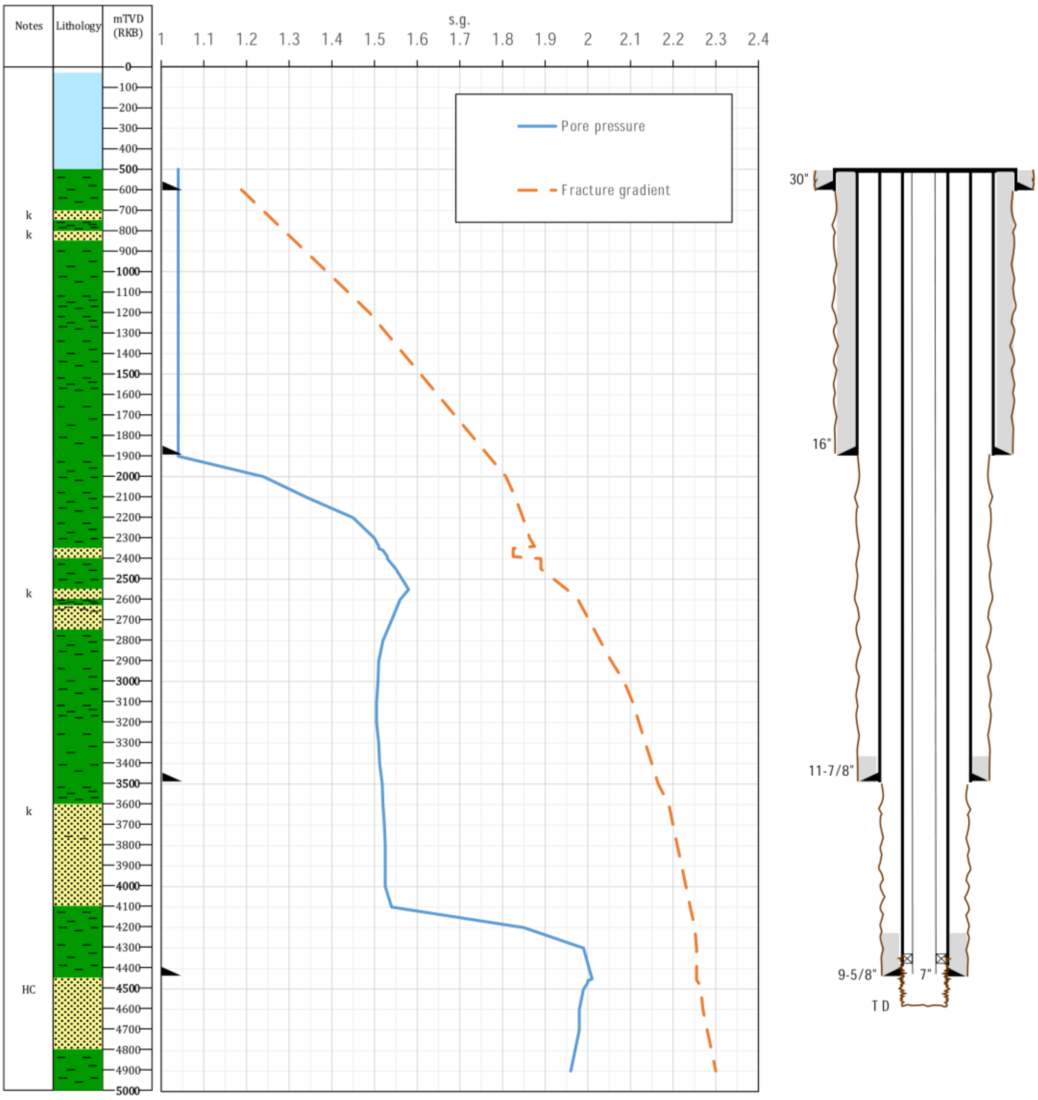

Figure 3-5: Casing Program - Not Considering P&A (Example)

3.6.2 Well Design - Considering P&A

This section will analyse proposed casing program from well abandonment point of view. To facilitate the analysis pressure plot is made, where gas gradient (0.19 s.g.) is plotted for stringers that has permeability (indicated by letter 'k'):

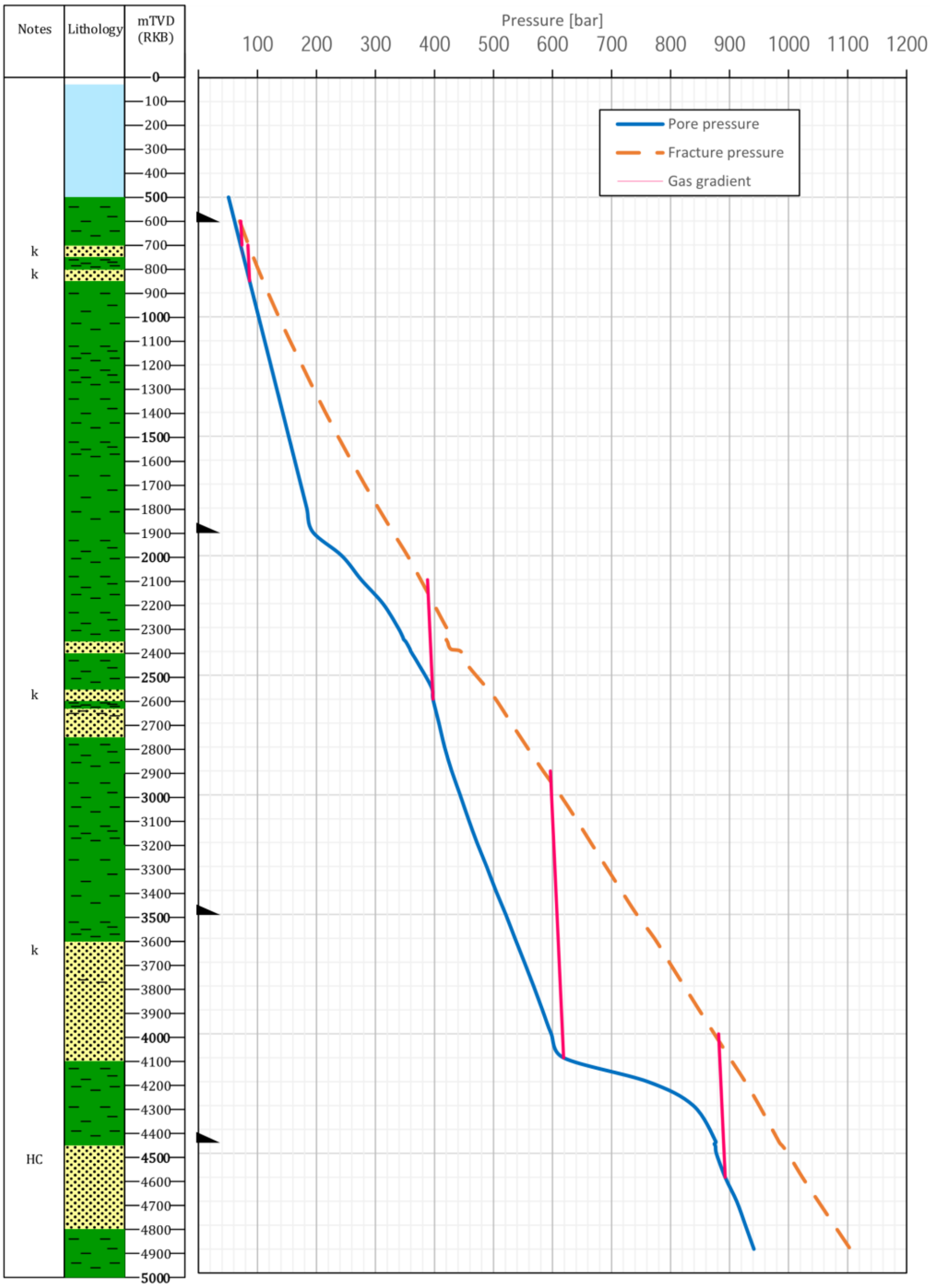

Figure 3-6: Pressure Plot and Gas Gradients (Example)

Gas gradients in the figure above were plotted from the base of permeable formations. Intersection of gas gradient curve with fracture pressure curve indicate shallowest depth for placement of permanent well barrier. Permanent barrier shall be placed in a way so that the pressure at the base of the barrier is lower than fracture pressure of formation. For sections that require primary and secondary well barriers this means that primary barrier needs to be placed in a way so that the pressure at the base of secondary barrier is not exceeding fracture pressure of surrounding formation.

Analysis of casing program will be performed from the bottom and up.

3.6.2.1 Production Casing

Casing cement is placed in the interval 4450 - 4250 mTVD (200m). Base of production packer (approx. 50 m in length) is placed at 4400 mTVD, meaning that approx. 100 m of cement is available for external well barrier classification. According to NORSOK Standard D-010, one can place a back-to-back barrier on top of the packer, provided that cement is verified by logging and that cement plug is placed on a solid foundation (pressure tested bridge plug). Having in mind that the best casing cement is located at the shoe and that lead cement is usually contaminated, it is suggested to increase casing cement to a length of 250 - 300 m. This will increase probability of finding good quality cement at intended permanent barrier depth. Consequently, back-to-back reservoir barrier shall be placed in the interval 4250 - 4350 mTVD. In order to ease future P&A operation, upper completion equipment must be placed at least 100 m above the top of production packer. Expandable cement is suggested for both casing and cement plugs. In this case, reservoir section can be abandoned without need of retrieving the tubing at reservoir abandonment stage.

Further up there is over pressurised permeable sand formation. Only one set of primary and secondary barrier is required. However, there is no annular cement right above these layers and there is only 100 m until previous (intermediate) casing. Gas gradient curve for this section suggests that permanent plug can also be placed within intermediate casing section. One can therefore easily abandon this layer by placing back-to-back barrier from 11-7/8” csg. shoe and up. It is suggested to place back-to-back barrier at the interval 3400 - 3500 mTVD. Alternatively by using dual casing perforate, wash and cement technology in intermediate casing or adjust intermediate casing shoe to 3400 mTVD and use single casing perforate, wash and cement technology to place approx. 100 m back-to-back barrier. To allow for use of PWC tool tubing shall be cut from 3550 mTVD. It is also recommended to increase intermediate casing cement to a length of 150 - 200 m.

3.6.2.2 Intermediate Casing

Intermediate section contains three sand formations one of which is permeable (middle one). Vertical separation between the lower and middle formations is approx. 25 m. Based on the pore pressure profile these formations can be regarded as one formation and hence require only one set of primary and secondary barrier. The upper formation can be isolated with one barrier. It is suggested to establish primary barrier for the lower and middle formations and primary barrier for the upper formation. The primary barrier for upper formation will also act as secondary barrier for middle and lower formations.

As tubing has been previously removed one can readily use dual casing perforate, wash and cement technology to abandon these formations. Single 50 m barrier shall be placed in the interval 2500 - 2550 mTVD and a single 50 m barrier in the interval 2300 - 2350 mTVD. The latter will act as a secondary barrier for lower formation.

3.6.2.3 Surface Casing

There are two permeable formations with normal pressure in this section. Based on the pore pressure profile, these can be regarded as one formation. Single 50 m surface plug can be placed in the interval 650 - 700 mTVD. It is not required to log cement in well construction phase in this case. Use of expandable cement shall be evaluated. Surface plug is planned to be installed with Suspended Well Abandonment Tool (SWAT), ref. Section 4.2.

3.6.2.4 Conductor Casing

Cement of this casing is not a part of permanent WBE.

3.6.2.5 Summary

It has been observed that for this particular example and P&A approach not many adjustments to the original casing design were required. Horizontal XMT enables removal of tubing without “disturbing” near-by network of connections and must be considered in design stage. The following abandonment approach is suggested:

- Abandonment of reservoir section can be performed from a vessel utilizing coiled tubing (ref. experience from GOM and assuming that such approach will be accepted by authorities).
- Abandonment of lower intermediate section (2300m - 3500m) will require a drilling rig.
- Abandonment of upper intermediate section (surface plug) can be performed from a vessel (SWAT).
- Cutting and removal of casings/wellhead can be easily performed from vessel of opportunity.

The following figure visualises proposed well abandonment schematic:

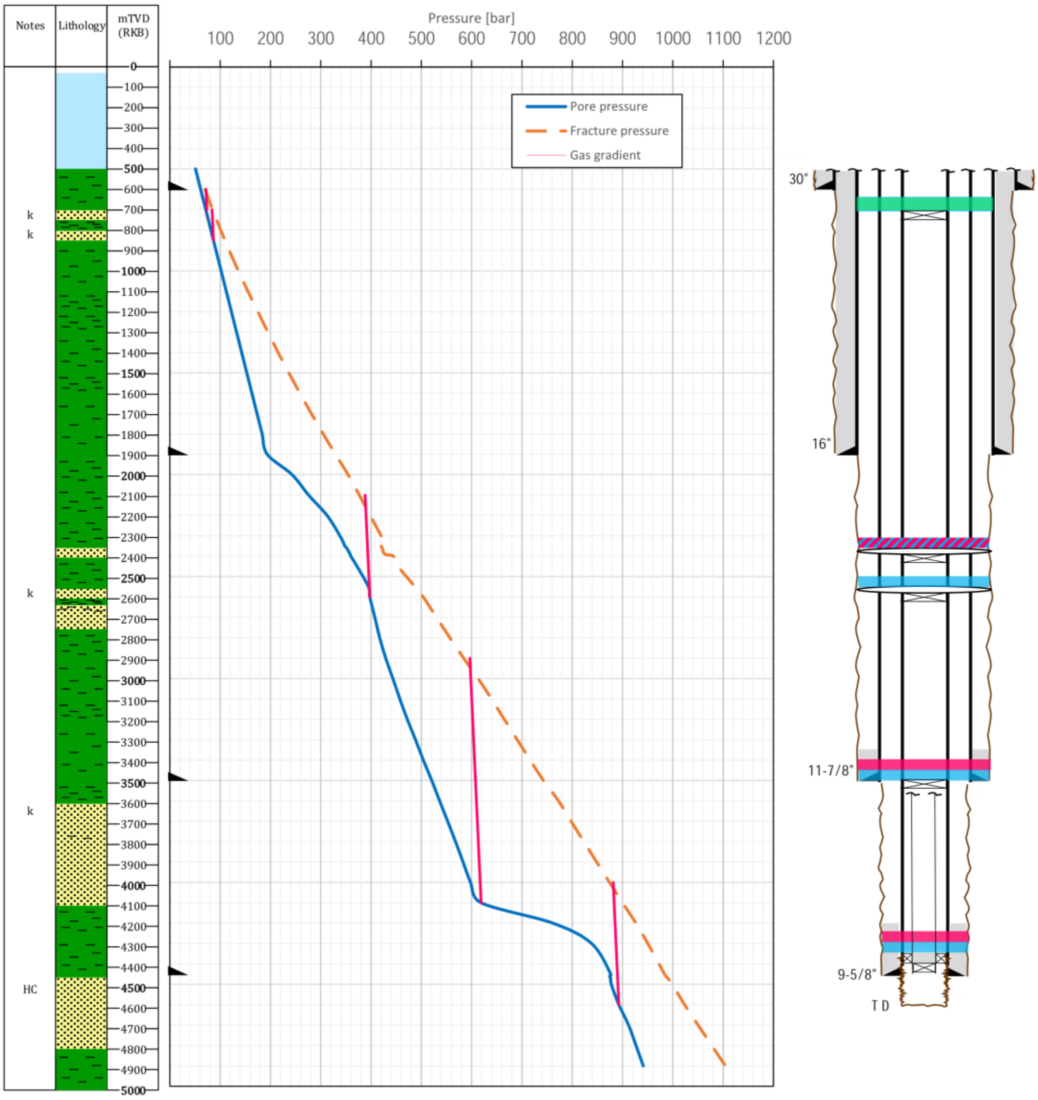

Figure 3-7: Well Abandonment Schematic (Example)

4 Modern Day Technologies for P&A

4.1 Light Well Intervention Vessel (LWIV) Operations

For the past two decades and until recently, day-rates of drilling rigs had an increasing trend thereby increasing cost of associated activities [77]. Operator companies saw the need to reduce operational costs and begun seeking means to do so.

Concept of Riserless Light Well Intervention (RLWI) in live subsea wells was merely known on NCS up until 2000, when it started to gain popularity. Interest for the concept on NCS may be associated with rigless P&A of a well in Tommeliten field in 2000 [78]. In fact, this project achieved several milestones for NCS [78-81]:

- Norwegian authorities for the first time gave consent to enter live well to a LWIV.
- It was the first riserless well intervention on a subsea field.
- It was the first rigless plugging of reservoir section, whereby mobile rig was used in the final part of plugging operation to cut and pull tubing and casing

Experience from P&A operation on Tommeliten field motivated Statoil to re-perforate two subsea wells on Heidrun field utilising same equipment and procedure as on Tommeliten field. This project also achieved several milestones for NCS [78]:

- It was the first diverless RLWI operation on NCS
- It was the first time when wireline tractor was used in a subsea lubricator

Complexity and number of RLWI operations increased over the last decade and today include many operations that can be performed on wireline [39, 78]:

- Well diagnostics and logging
- Zone isolation by plug insertion or straddle operation
- Tractor operations
- Milling of short scale bridges
- Well killing and pumping operations
- Perforations
- Replacement of valves (DHSV/GL)

Utilising both LWIV and drilling rig in P&A campaign can greatly reduce project cost as day rates for LWIV are much lower compared to drilling rigs. For instance on Troll Oseberg Gas Injection project (NCS) preparatory work for P&A Phase 1 was handled riserless by LWIV. The following work was performed on five wells: well killing, deep-set plug installation, tubing punching, annular fluid displacement, shallow tubing and annulus plugs installation and XMT removal [39]. Abandonment of earlier suspended subsea exploration well on Gyda field (NCS) is another example where P&A Phase 2 was handled riserless by LWIV where only placement of environmental plug was needed [82]. P&A Phase 3 can easily be performed not only from LWIV but almost from any vessel that has sufficient deck space and required crane capacity.

It has been estimated that if P&A efficiency of drilling rigs can be matched, there is a potential of saving approx. 70 % of well abandonment cost [83]. Therefore, there is a high focus in the industry to develop a method of complete P&A of live well from vessel.

Suitable vessels have a cost of 30-40 % of a rig and are able to move quickly between locations what represent additional time and cost savings. In addition, it is safer and more efficient to perform operations related to removal of wellheads and small structures with a vessel [84]. Efficiency and improved HSE are easily attainable as personnel on vessel are performing routine abandonment work compared to the drilling rig crew. Vessel operations can also be scheduled for seasons with calmer sea state in order to reduce NPT (wait on weather time). For a single operator vessel campaign for cutting wellheads is economical when at least two wellheads are planned to be cut in the same campaign [46]. Even greater economy can be attained in the multi-operator and multi-well campaigns as risk associated with wait on weather, mobilisation/demobilisation costs as well as transit time costs are shared [84]. Contractors constantly log operational parameters and can thus provide metrics for RLWI operations. This provides confident time estimates that are used to plan the jobs [85].

It should be noted that not all wells are suitable for 100% rigless P&A operations although the concept was proved possible [78].

In can be argued that, in order to enable 100% rigless and riserless abandonment of suitable wells on NSC the following aspects shall be accounted for/satisfied in well design/construction phase:

- Logged and confirmed annular cement seal of production casing.

- No control/instrument lines throughout permanent well barrier interval(s).
- Subsurface lithology log that indicates no need of placement of intermediate plugs
- Short (upper) section of production tubing can be cut and retrieved with vessels pipe handling equipment.

4.2 Setting Environmental Plug with LWIV

Suspended Well Abandonment Tool (SWAT) was designed by Claxton Engineering in mid-90' for placement of surface (environmental) cement plug across the well without need of retrieving casing strings. This operation requires reservoir section to be abandoned upfront [45]. Since introduction in 1996, the tool was successfully used on 16 multi-operator campaigns on UKCS [84] and for the first time on NCS in 2014 on Gyda field [82].

Presented SWAT configuration allows cement placement across B and C-annuli as well as placement of the cement plug inside the casing. The tool is landed using umbilical and can be deployed from both vessel and platform. After the tool has been landed, packers are inflated and cavities between and below the packers are pressure tested. Inner casing is perforated below the lower packer to evaluate its pressure state. Upper perforation guns within the tool are then fired to establish circulation path and B-annulus is then circulated-out, washed and cemented. After B-annulus cement has been set and pressure tested, similar procedure is performed to cement C-annulus. Lower perforation guns are dropped into the well when cement pumping starts. Cement plug inside the inner casing is placed during the latter operation. After the final pressure test has been performed, severance and recovery of the wellhead can commence. Recently developed extension module for SWAT allows placing intermediate well plugs. This option increases number of wells that can be abandoned with SWAT tool as well as work that can be transferred from drilling rig to vessel [86].

Despite of maturity of SWAT concept, there is room for improvement. For instance, it would be beneficial to increase effective circulation rate that is attainable with a tool/set-up. One might also encounter a casing hanger seal leak after the casing perforation. This suggests that R&D work on perforation guns might be beneficial in order to minimise shock loads [82].

Tools that have similar operating principle to SWAT are available from different vendors.

4.3 Abrasive Cutting Technology

Once environmental cement plug has been set, severance and retrieval of wellhead and well casings can begin. This operation is commonly transferred to ‘rig chase vessels’ if environmental cement plug was placed earlier by drilling rig [46]. If environmental cement plug was placed by vessel, severance of wellhead and casings can start straight away.

Sabre abrasive cutting tool was developed by Claxton Engineering in mid-90’ to be used together with their SWAT tool. The tool is capable to cut 6⅝” to 30” casings in one operation regardless of casing eccentricity and loads. The tool also allows cutting casings individually [84, 87].

Such tools contain manipulator, rotating head with one nozzle and centralisers (to stabilise tool in operation) [87]. Some vendors utilise cutting heads with three nozzles phased at 120° angle for self-centralisation [88]. The tool is connected to the pumping spread through umbilical, which is also used to land the tool onto the wellhead [87].

In order to optimise the operation, it is beneficial to clarify casing characteristics such as wall thickness, eccentricity, cemented annuli during the planning phase. This allows to choose appropriate nozzle size, cutting head rotation speed and pressure across the nozzle(s) [89].

Cutting is achieved by pointing a high-pressure jet flow of water, air and garnet mixture at the casing from within the casing [87]. Cutting of casings can be performed under pressures ranging in between 350 bar and 3500 bar [88] and may take from 4 to 12 hours to complete depending on casing programme [46]. Cutting operations are typically monitored by observing surface pressure, cutting heads nozzle position and utilising acoustic system mounted on manipulator. Hydraulic jacking system might be utilised to proof complete cutting of all casings. Abrasive jetting tools can be easily used at the depth up to 450 m and beyond [89].

If combo cutting and removal tool is used, the wellhead and casings can be lifted by crane immediately after the cut. Tension of 30-40 ton is typically needed to lift the wellhead with cut casings. However, higher tension might be required to free-up wellhead due to conductor-to-cement bonding. Based on this, vessels planned for severance and removal of wellheads shall have crane capacity of at least 100 ton. It is therefore recommended to install conductor sleeves on the upper section of conductor to minimise friction and thereby ease casing removal after the cut [46].

4.4 P&A by Re-establishing Cap Rock

Several years ago, a novel concept has been introduced to the industry by Interwell. Company aims to P&A wells rig-less, by re-establishing cap rock. The idea is to melt and re-crystallise sedimentary rock/sediments the same way magma does. The great examples of this process are sills and dikes that can be easily observed on selected outcrops [90].

In order to achieve melting temperatures of rocks and well components thermite has been chosen as a source of heat [91]. Thermite is a mixture of metal powder (typically aluminium) and metal oxide (iron oxide, copper oxide, nickel oxide etc.). When ignited, thermite reacts violently and produces extremely exothermal reaction that can reach up to 3000 °C. Thermite contain its own oxygen supply and hence do not require external air supply [92]. Experimental work has showed that aluminium and magnetite mixture (24/76 by weight) produces a melt that simulates basaltic magma. When such mixture is mixed with quartzo-feldspathic sand in ratio 3:1, a silicate melt is obtained [93]. Content of final mixture, however, is not disclosed by the company. It is anticipated that final thermite mixture might vary depending on the subsurface lithology.

According to the concept, there is no need of removing any of equipment from the well prior to abandonment. Operation only requires installation of deep-set barrier that must be covered with heat protecting material. Both barrier and heat protecting material will be installed on wireline during the first run. Next run(s) will deploy thermite mixture in specialised container run on electrical line. Once deployed, thermite will be ignited thereby producing a mixture of molten rock and metal that together with surrounding rock/sediments will form cross-sectional barrier [91].

DNV GL is participating in qualification of technology which is planned to be tested on four pilot wells by the end of 2016 [91, 94].

5 P&A Considerations of Operator Companies

There are many new field developments on NCS, both platform and subsea. It was therefore of an interest to get hold of practical information regarding planning of P&A activities for some of the fields. A questionnaire was made (ref. Appendix B: Questionnaire) and sent out to a number of operator companies. Due to limited resources and high workload, the answers were received from only two operator companies. Based on the agreement with respondents, some formulations presented below were slightly changed due to confidentiality. It shall also be noted that some answers were provided based on the respondents experience from other fields than the one questionnaire was aiming to get the information about.

5.1 Formation Logging

According to NORSOK D-010, all sources of inflow shall be identified and isolated.

Q: What logging tools/logs do you use to identify 'all' sources of inflow?

O1: Typically, the logging programme in overburden is limited and hence it could prove difficult to identify all sources of inflow. However, LWD tools as GR/Res are typically included, this data together with drilling parameters as background gas, connection gas and cuttings in returns could be used in addition to the LWD data.

O2: LWD tools (GR, RES, Dens, Neu, APWD) are used to identify sands. If there are doubts (and the info is required for barriers) a mini Drill Stem Test (DST) may be run as well. Gas data from mud loggers is also used as input.

My comment: These answers were somewhat expected as they represent current industry practice. Modular formation Dynamics Tester (MDT) can also be used to help in identifying zones with possible flow potential.

Q: Is such logging performed during well construction, P&A phase or both?

O1: The logging data is normally included during well construction. However, if data is inconclusive additional logging might have to be performed during the P&A phase.

O2: Both, if required.

Q: Do you use nuclear magnetic resonance logging tool to aid identification of sources of inflow?

O1: I am not aware of any NMR tools run in overburden formations; I believe the NMR typically is run through the reservoir section only.

O2: No, not used in overburden.

My comment: As pointed out, NMR tool is typically run through a reservoir section, but can readily be utilised to verify flow potential in other sections. Obviously, addition of this log type increases project cost. However, better understanding of overburden and potential safety gains cannot be underestimated.

It can be argued that log interpretation is dependent on the interpreter.

Q: How many people perform evaluation of subsurface logs aiming to identify 'all' sources of inflow? Is 3rd/independent party involved in this process? In your opinion, is there a need to involve independent party in this process?

O1: The interpretation can be done in-house and in addition by 3rd party.

O2: Many people are involved before sources of inflow are concluded, including people with field knowledge and HQ. No need to involve 3rd party.

5.2 B-annulus (subsea wells)

According to NORSOK D-010, B-annulus of subsea wells with gas lift shall be designed to withstand the effect of thermal induced pressure. Monitoring of B-annulus in subsea wells was not possible until recently. Recent sensor development (e.g. Roxar) allows for monitoring of B-annulus. Knowing of B-annulus pressure at all times is advantageous from both production and P&A point of view.

Q: Do you/Company have any experience utilising such technology or plan for it?

O1: We are planning to install a B-annulus monitoring system.

O2: Have used B-annulus monitoring in well for gas lift. It is however a challenge to get hold of equipment due to long lead times, and shorter planning horizons.

My comment: It is great that innovative technology has short path to the application. However, it was interesting to find out that equipment lead-time may pose a difficulty. Probably subsea equipment standardization would reduce time required for custom tailoring of monitoring equipment.

5.3 Casing Cement

Reference is made to NORSOK D-010 for the minimum lengths of casing cement.

Q: Do you design casing cement to satisfy minimum requirements only, or do you typically extend casing cement length above these requirements? If yes, please indicate by what length and provide short reason.

O1: The cement lengths pumped are typically more than minimum requirements from NORSOK. This to ensure that when logging the cement height that the actual top of cement is above the source of inflow and according to minimum requirements from NORSOK.

O2: Cement lengths planned to satisfy requirements, plus excess. In some instances, extra cement is added if a future sidetrack is planned.

Several studies have indicated that expandable cements might be a better option when it comes to primary cementing operations.

Q: What cement types are commonly used to cement different casings?

O1: I have used expandacem for the P&A application, however not during well construction. However, I agree it might be beneficial also during well construction.

O2: G-cement, silica, foam and expandacem are used in various section depending on temperature, ECD, etc.

5.4 Primary Cementing Operation

Casing reciprocation and rotation may increase quality of primary cementing job. Literature review has indicated that some operators may prohibit casing reciprocation in fear of compromising the job as the string might set when elevated; rotation may also be prohibited if hanger-locking mechanism does not allow for this.

Q: Do you reciprocate and/or rotate casings in primary cementing operations?

O1: Casing strings are normally landed in the wellhead prior to cementing, therefore rotation and reciprocating could damage the wellhead seal area. However, liners, which are run on drill pipe, are typically rotated during the cement job.

O2: No, only liners if possible.

Q: Do you have any operational suggestions that may increase success rate of primary cementing job?

O1: Centralisation of the casing string is very important for a good cement job. Simulations of the cement programme with flowrates and spacer type and volumes are important for a successful cement job.

O2: Good pumping practices, avoid pressure spikes. Proper circulation before cementing to ensure clean annulus. Lower mud rheology before cementing (towards TD of section) to reduce ECD.

My comment: It is noted that suggestions above coincide with general recommendation for primary cementing outlined in Section 3.2.4.

Most recent field tests suggest that use of casing vibratory tool can optimise primary cementing operations (operations are performed quicker, fluid channelling and voids are reduced).

Q: Do you/Company have any experience utilising such technology or plan for it?

O1: No plans that I am aware of.

O2: No.

My comment: It can be thought that vibratory tools are new to the market. Case studies were presented at the IADC/SPE Drilling Conference and Exhibition in March 2016. It is therefore expected that some time will be required to penetrate the market.

5.5 Verification of Primary Cement Job

It is known that both sonic and ultrasonic cement logging tools have pros. and cons. Combination of two provides better 'picture' of casing cement compared to what both technologies can provide individually.

Q: Please specify logging tools/logs types that you use to verify primary cement job during well construction phase.

O1: The Schlumberger USIT or Isolation Scanner and the Baker Atlas SBT tools are tools that I have used.

O2: Both sonic and ultrasonic cement logging tools are used.

Q: Do you use different 'logging packages' to verify cement of production casing compared to other casings? If yes, provide short reason.

O1: No, I have used the logging tools as listed above for all the casing strings.

O2: Same package used for all verification logs, but all cement jobs are not logged.

Q: How do you normally verify sealing of casing cement in construction stage for different casings?

O1: Depends what is the purpose of the cement. If the casing cement is for drilling only then a FIT or LOT together with job performance will be sufficient to qualify the cement. If the cement is for the production casing and the cement is part of the primary and secondary barrier then the cement is normally logged with a cement bond log.

O2: Logging if casing is a barrier during production, FIT/LOT if not. No test of conductor, as no BOP present for testing.

Q: Would you plan for casing cement logging prior to P&A campaign, given that initial cement log was interpreted to be very good and there were no sustained casing pressure or any other operational anomalies reported throughout construction and production phases?

O1: This will have to be risk assessed on a case-by-case basis. However, if the case as described above, then it quite possibly would be evaluated not to perform a new cement bond log.

O2: No.

It can be argued that log interpretation is dependent on the interpreter.

Q: How many people perform evaluation of cement logs? Is 3rd/independent party involved in this process? In your opinion, is there a need to involve independent party in this process?

O1: Yes, I believe that a 3rd party shall interpret the logs to get a second opinion.

O2: Cased hole logging group performs interpretation. Clear cases are checked by interpreter and verifier, when in doubt the entire group discuss. The supplier is included if needed.

My comment: Permanent well abandonment implies that any future well entry is impossible. Because of great responsibility of the operator company to abandon the well with zero leaks ‘for the eternity’, it might be a good idea to get a second opinion from neutral party to certify barrier elements.

5.6 Oil & Gas UK P&A Classification

Q: Do you use Oil & Gas UK P&A classification and P&A well codes when planning for and performing P&A jobs? If yes, are codes included in the well barrier schematic?

O1: I have not used UK P&A classifications.

O2: No.

My comment: Based on the answers it might be presumed that gains by implementing such system has not been sought by operator companies.

5.7 P&A Challenges

Q: To your/Company experience, what are the common challenges when abandoning 'newly' designed wells (e.g. exploratory and appraisal)?

O1: The newly designed wells are according to NORSOK D-010, Rev 4 and the plan for the P&A of the well is included in the well delivery / well construction process. Hence, this is less challenging then P&A of older wells, which are not designed according to the NORSOK Standard. The challenge is normally that Distinct Permeable Zone (DPZ) in the overburden are not covered by casing cement which might lead to a very costly P&A with possible section milling or PWC operation.

O2: Don't see a big difference between new and old wells (in my experience).

My comment: I would agree with the first answer above. The example case presented in Section 3.6 illustrates that designing well according to the Standard makes abandonment process simpler, as well design might be easily adjusted to account for expected subsurface and operational conditions.

5.8 Control Lines

In order to optimise/ease P&A of reservoir section of the well, it might be feasible to move chemical injection valves and other completion equipment further up above the packer. This will allow placing cement without need of removal of tubing with control lines at that stage.

Q: Do you perform this evaluation when designing a well? If such design is applied, what kind of tubing/liner material is used to prevent scale/deposits on the untreated tubing section (between packer and chemical injection valve)?

O1: Yes, the evaluation to move control lines to a distance above the production packer to facilitate the position of a future cement plug is normally performed.

O2: Don't have chemical injection in wells I've been involved.

Q: At what distance from the packer do you typically place injection valves or any other completion components (the one closest to the packer)?

O1: If possible, it is desirable to position the completion items more than 100m above the production packer to facilitate a cement plug for a future P&A.

My comment: The answer is a clear indication that operator company has future P&A in mind and is probably aiming for back-to-back plug in the reservoir section.

5.9 Permanent Well Plugs

Reference is made to NORSOK D-010 for the minimum lengths of permanent well plugs.

Q: Do you design cement/material plugs to satisfy minimum requirements only, or do you typically extend cement/material length above these requirements? If yes, indicate by what length and provide short reason.

O1: The lengths are normally more than minimum lengths. The actual length could be twice the minimum requirement or more.

O2: Planned to satisfy minimum requirements or more if it is operationally more effective.

Q: Do you use other plugging materials than cement?

O1: No, I have not used anything other than cement.

O2: No, not for permanent plugs.

My comment: Based on the answers it can be presumed that alternative plugging materials are not that popular. Maybe it is due to lack of industry wise utilisation of alternative solutions.

5.10 Equipment (subsea well)

Horizontal XMT might be viewed as a better option for subsea wells from P&A point of view, as tubing can be retrieved with less effort.

Q: What type of XMT do you typically use on subsea wells?

O1: Horizontal XMTs are typical for subsea wells, that is correct.

O2: Horizontal XMTs on all current wells in sector.

5.11 P&A in Well Design

PSA urges industry to increase focus on P&A when planning and drilling new wells.

Q: At what stage in well design do you perform P&A evaluation (before Authority for Expenditures (AFE) or after)?

O1: The plans for P&A are included in the well delivery process and the planned schematic for the future P&A is included in the drilling program.

O2: P&A considered in early planning, both feasibility and cost.

Questions related to a certain well:

Q: Can you comment on why casing seats were placed at certain depths?

O1: Casing seats are evaluated based on offset well experience and with respect to the required kick margins for drilling the section. Another driver to be evaluated is the production loads with associated loads.

Q: Were there/are there any challenges (uncertainties) when considering P&A in the well design phase for this well?

O1: DPZ's in the overburden will have to be evaluated with respect to casing cement. One option is to cement above the DPZ. However, this must be carefully evaluated not to create enclosed casing annuli with Annular Pressure Build-up (APB) during production. If not possible to cement above the DPZ for the reason described, then the cement plugs can be placed across the previous shoe, provided the shoe has sufficient formation strength.

Q: Having in mind P&A schematic of the well above, has it been already decided what equipment/rig/vessel will be used to abandon the well? For example: drilling rig will perform all P&A activities; or drilling rig will perform only part of activities while less expensive methods will be used to perform remaining activities.

O1: Normally the tubing will have to be retrieved prior to setting the surface barriers; hence, a drilling rig is required for at least parts of the operation. A light intervention vessel can be used for setting barriers that does not include retrieval of tubulars.

O2: A feasible method is identified, but nothing is decided before detailed planning performed for P&A.

Conclusive Thought

Based on the answers provided to the questionnaire it is evident that operator companies has strong focus on P&A when designing new wells.

6 Discussion

Success and cost of well abandonment can be partially viewed as a consequence of well design, which in turn is reliant on understanding of subsurface environment. Although one can readily utilise data from offset wells for initial design feasibility, the wells shall be designed individually. The subsurface data and planned target depth alone will dictate many parameters on how the well design should be. The more demanding is subsurface environment, the more challenging will be realisation of well construction and consequently future well abandonment.

Subsurface Lithology

In order to plan for permanent barriers one must first find out what zones needs to be isolated. According to NORSOK Standard D-010 *"all sources of inflow shall be identified and documented"*. While operator and service companies are doing their best in identifying zones with flow potential it can be argued that this requirement might be difficult to fulfil in some cases. Standardizing operational practices, use of same type of tools and most important personnel would of course improve interpretations; however, it is not practically achievable unless a single special tool would be introduced to the market and would be run in all wells on the Shelf thereby producing same logs with the same error set.

Statoil has previously initiated project for evaluation of flow potential in the overburden where two conclusions of importance were that:

- Zones with flow potential does not always manifest on standard logs
- 'Search' for such zones should be conducted during whole life cycle of the well

Recommendation is given to use NMR log in overburden to aid identification of zones with flow potential. However, feedback from the industry revealed that this log type is not considered in new developments. Inclusion of additional log type will likely only slightly increase overall well cost but the benefits can be considerable if the criticality of not discovering a certain zone is high. On another hand a question can be raised whether it is necessary to identify 'all' zones that are not manifesting during conventional logging and geological analysis of cuttings. It can be thought that such zones will have limited effect on the abandoned well, especially if recently released risk-based well abandonment guideline from DNV GL is taken into consideration.

Primary Cementing

With the knowledge of the zones to be isolated, it is easier to distribute resources and have extra focus on the casing cement that will be used as a barrier element in the future abandonment. Correct execution of the job and proper cement chemistry will prevent need of repair jobs and any SCP development thereby making future P&A safer and more cost effective.

Recent case studies for casing vibratory tool indicate that technology is not only accelerate casing installation process but also promotes uniform flow of fluid outside the casing due to vibration. It can be expected that coupling the tool with good cementing practices will help to compensate for and overcome some of today's operational challenges.

Based on the feedback from the industry it was found that recommendations regarding primary cementing operations coincide with what is considered being a good practice on the NCS: good casing centralisation, simulation of circulation and cement job. Reciprocation and rotation of casing is not normally performed. However, rotation of liners is typically performed if possible.

It remains to be seen whether casing vibratory tool will get wide implementation within the industry and whether the tool can eliminate the need of liner rotation (or casing rotation/reciprocation where applicable).

Evaluation of Primary Cement Job

It can be argued that with evaluation of cement job lies great responsibility. It is therefore necessary to utilise all available data and resources in evaluation process. Depending on organization within the operator company that evaluates such logs it might be a good idea to involve independent party to get second opinion.

Because there are different vendors of logging tools the results obtained cannot be compared directly. As mentioned earlier, introduction of one standard tool to the Shelf would ease interpretations.

Feedback from the industry indicates that NORSOK Standard D-010 is followed when it comes to validation of casing cement in different sections and that both sonic and ultrasonic logging tools are used. Although logging tools are under constant improvement, the giant leap in development is yet to be made.

P&A in Well Design

Example case (Section 3.6) and feedback from the industry indicate that NORSOK Standard D-010 does a good job in defining a framework for well design that accounts for future well abandonment. The design of the well is then further adjusted based on operator company experience and industry practice.

The focus is given for abandonment of reservoir section. Thus not only well but also completion is adjusted to make future P&A as easy as possible. For instance, tail pipe below production packer is designed to accommodate future bridge plug that will be used as a foundation for reservoir plug. Another example is that completion components that require control lines are installed at least 100 m above production packer (if possible) in order to 'delay' tubing removal. Casing cement that is planned to be a part of future barrier is always logged.

Inclusion of P&A schematic in drilling programme makes everyone aware of future P&A plans and any challenges. Feasibility study for well abandonment is also performed, but final methodology is chosen only during detailed planning which would be conducted in the future.

P&A Classification

Although Oil & Gas UK P&A classification does not influence the process of well design, it can be useful tool for planning outstanding P&A activities for operator companies. It is anticipated that availability of such well status codes on the online map (like NPD's) would help planning of abandonment activities in certain regions and would ease planning for multi-operator and multi-well abandonment campaigns thus reducing the overall abandonment cost for each operator.

Feedback from the industry indicates that such classification is not used. It can be therefore assumed that objective and main goal of this classification is not fully understood or that there is no immediate need of such classification on NCS. Perhaps further awareness of such classification shall be highlighted and presented on different platforms and arenas for the industry if authorities envision benefits of implementing such a system on the Shelf.

7 Conclusions

Objective of this thesis was to study possible approaches for considering well abandonment in the well design stage. The thesis provides overall picture of well design and requirements for well abandonment on the NCS and UKCS along with historical background. A literature study was conducted with the aim of identifying important well design parameters that have impact on future abandonment activities. Several modern day P&A technologies and concepts were also presented. To visualise the theory, example case of well design with emphasis on future abandonment was presented and discussed. In order to compare theory with practice industry was contacted and much valued response was received.

The main findings of the thesis are summarised in the following:

- In order to ease future P&A activities the following parameters shall be thoroughly evaluated and planned for during the well design:
    - Subsurface lithology (in order to identify and account for 'all' permeable zones). Inclusion of NMR log might contribute for better mapping of subsurface.
    - Primary cementing job including suitable design of cement that matches expected subsurface conditions (this will decrease probability of cement corrosion/failure and future SCP development). Casing vibratory tool can be a potential game changer when it comes to installation and cementing of casings.
- Design of completion shall also be taken into account when planning for effortless reservoir section abandonment (removal of tubing can be delayed).
- When well is designed according to latest revision (four) of NORSOK Standard D-010 not that many adjustments to design are required to facilitate future well abandonment (this is visualised by example case and also confirmed via feedback from the industry).
- Modern day P&A techniques/tools do not have special requirements for the well design but are rather universal.
- P&A well classification according to Oil & Gas UK is not used on NCS.

Recommendations

In order to make stronger focus on P&A in the Standard one could emphasize link between the well design and P&A even more; guidance on well completion design that considers P&A could be given. Additionally: acceptable limits of considering several reservoirs within the 'same' pressure regime should be given as a range; it should also be made clear whether the top, bottom or average height of reservoir shall be used in calculations when calculating shallowest plug setting depth.

Having in mind that the Standard requires well to seal for 'eternity' there is no requirement or provision for monitoring of permanently abandoned wells (say each 50 or 100 year). Monitoring in such case either can be performed with specialized vessel/ROV or specialized equipment/stations such as Biota Guard. Alternatively aerial or satellite surveillance programme could be established and sponsored by the operator companies. The standard should also define acceptable and unacceptable leakage rates if such should be discovered in the future and guidance on how to proceed should be given.

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Appendix A: Subsurface Pressure Data

Figure 3-2 to Figure 3-7 were plotted based on the following subsurface pressure data:

TVD (RKB)	PP	FG	PP & Riser Margin	Median Line	PP	FG
[m]	[s.g.]	[s.g.]	[s.g.]	[s.g.]	[bar]	[bar]
0	-	-	-	-	-	-
100	-	-	-	-	-	-
200	-	-	-	-	-	-
300	-	-	-	-	-	-
400	-	-	-	-	-	-
500	1.040	-	-	-	50.96	-
600	1.040	1.188	-	1.114	61.15	69.85
700	1.040	1.238	-	1.139	71.34	84.93
800	1.040	1.288	-	1.164	81.54	100.98
900	1.040	1.338	-	1.189	91.73	118.01
1000	1.040	1.388	-	1.214	101.92	136.02
1100	1.040	1.438	-	1.239	112.11	155.02
1200	1.040	1.488	-	1.264	122.30	174.99
1300	1.040	1.528	-	1.284	132.50	194.67
1400	1.040	1.568	-	1.304	142.69	215.13
1500	1.040	1.608	-	1.324	152.88	236.38
1600	1.040	1.648	-	1.344	163.07	258.41
1700	1.040	1.688	-	1.364	173.26	281.22
1800	1.040	1.728	-	1.384	183.46	304.82
1900	1.040	1.768	1.062	1.404	193.65	329.20
2000	1.240	1.808	1.327	1.524	243.04	354.37
2100	1.340	1.830	1.453	1.585	275.77	376.61
2200	1.450	1.848	1.589	1.649	312.62	398.43
2300	1.500	1.864	1.645	1.682	338.10	420.15
2340	1.510	1.875	1.654	1.693	346.27	429.98
2350	1.510	1.825	1.654	1.668	347.75	420.30
2360	1.520	1.825	1.666	1.673	351.55	422.09
2390	1.530	1.825	1.676	1.678	358.36	427.45

TVD (RKB)	PP	FG	PP & Riser Margin	Median Line	PP	FG
[m]	[s.g.]	[s.g.]	[s.g.]	[s.g.]	[bar]	[bar]
2400	1.530	1.890	1.675	1.710	359.86	444.53
2450	1.550	1.890	1.697	1.720	372.16	453.79
2550	1.580	1.951	1.727	1.766	394.84	487.55
2600	1.560	1.977	1.698	1.769	397.49	503.74
2700	1.540	2.003	1.668	1.772	407.48	529.99
2800	1.520	2.029	1.638	1.775	417.09	556.76
2900	1.510	2.055	1.621	1.783	429.14	584.03
3000	1.508	2.085	1.614	1.797	443.35	612.99
3100	1.505	2.105	1.606	1.805	457.22	639.50
3200	1.505	2.120	1.603	1.813	471.97	664.83
3300	1.510	2.135	1.605	1.823	488.33	690.46
3400	1.512	2.150	1.604	1.831	503.80	716.38
3500	1.518	2.165	1.608	1.842	520.67	742.60
3600	1.520	2.190	1.607	1.855	536.26	772.63
3700	1.523	2.200	1.608	1.862	552.24	797.72
3800	1.525	2.210	1.608	1.868	567.91	823.00
3900	1.525	2.220	1.605	1.873	582.86	848.48
4000	1.525	2.230	1.603	1.878	597.80	874.16
4100	1.540	2.240	1.618	1.890	618.77	900.03
4200	1.850	2.251	1.968	2.051	761.46	926.51
4300	1.990	2.255	2.123	2.123	838.59	950.26
4450	2.010	2.255	2.141	2.133	876.56	983.41
4460	2.000	2.256	2.129	2.128	874.16	986.05
4470	2.000	2.260	2.129	2.130	876.12	990.02
4500	1.990	2.265	2.116	2.128	877.59	998.87
4600	1.980	2.270	2.102	2.125	892.58	1023.32
4700	1.980	2.280	2.099	2.130	911.99	1050.17
4800	1.970	2.290	2.085	2.130	926.69	1077.22

Appendix B: Questionnaire

1) Formation logging

According to NORSOK D-010, all sources of inflow shall be identified and isolated.

Q: What logging tools/logs do you use to identify 'all' sources of inflow?

Q: Is such logging performed during well construction, P&A phase or both?

Q: Do you use nuclear magnetic resonance logging tool to aid identification of sources of inflow?

It can be argued that log interpretation is dependent on the interpreter.

Q: How many people perform evaluation of subsurface logs aiming to identify 'all' sources of inflow? Is 3rd/independent party involved in this process? In your opinion, is there a need to involve independent party in this process?

2) B-annulus (subsea wells)

According to NORSOK D-010, B-annulus of subsea wells with gas lift shall be designed to withstand the effect of thermal induced pressure. Monitoring of B-annulus in subsea wells was not possible until recently. Recent sensor development (e.g. Roxar) allows for monitoring of B-annulus. Knowing of B-annulus pressure at all times is advantageous from both production and P&A point of view.

Q: Do you/Company have any experience utilising such technology or plan for it?

3) Casing cement

Reference is made to NORSOK D-010 for the minimum lengths of casing cement.

Q: Do you design casing cement to satisfy minimum requirements only, or do you typically extend casing cement length above these requirements? If yes, please indicate by what length and provide short reason.

Several studies have indicated that expandable cements might be a better option when it comes to primary cementing operations.
Q: What cement types are commonly used to cement different casings?

4) Primary cementing operation

Casing reciprocation and rotation may increase quality of primary cementing job. Literature review has indicated that some operators may prohibit casing reciprocation in fear of compromising the job as the string might set when elevated; rotation may also be prohibited if hanger-locking mechanism does not allow for this.
Q: Do you reciprocate and/or rotate casings in primary cementing operations?

Q: Do you have any operational suggestions that may increase success rate of primary cementing job?

Most recent field tests suggest that use of casing vibratory tool can optimise primary cementing operations (operations are performed quicker, fluid channelling and voids are reduced).
Q: Do you/Company have any experience utilising such technology or plan for it?

5) Verification of primary cement job

It is known that both sonic and ultrasonic cement logging tools have pros. and cons. Combination of two provides better 'picture' of casing cement compared to what both technologies can provide individually.
Q: Please specify logging tools/logs types that you use to verify primary cement job during well construction phase.

Q: Do you use different 'logging packages' to verify cement of production casing compared to other casings? If yes, provide short reason.

Q: How do you normally verify sealing of casing cement in construction stage for different casings?

Q: Would you plan for casing cement logging prior to P&A campaign, given that initial cement log was interpreted to be very good and there were no sustained casing pressure or any other operational anomalies reported throughout construction and production phases?

It can be argued that log interpretation is dependent on the interpreter.
Q: How many people perform evaluation of cement logs? Is 3rd/independent party involved in this process? In your opinion, is there a need to involve independent party in this process?

6) Oil & Gas UK P&A classification

Q: Do you use Oil & Gas UK P&A classification and P&A well codes when planning for and performing P&A jobs? If yes, are codes included in the well barrier schematic?

7) P&A challenges

Q: To your/Company experience, what are the common challenges when abandoning 'newly' designed wells (e.g. exploratory and appraisal)?

8) Control lines:

In order to optimise/ease P&A of reservoir section of the well, it might be feasible to move chemical injection valves and other completion equipment further up above the packer. This will allow placing cement without need of removal of tubing with control lines at that stage.
Q: Do you perform this evaluation when designing a well? If such design is applied, what kind of tubing/liner material is used to prevent scale/deposits on the untreated tubing section (between packer and chemical injection valve)?

Q: At what distance from the packer do you typically place injection valves or any other completion components (the one closest to the packer)?

9) Permanent well plugs

Reference is made to NORSOK D-010 for the minimum lengths of permanent well plugs.
Q: Do you design cement/material plugs to satisfy minimum requirements only, or do you typically extend cement/material length above these requirements? If yes, indicate by what length and provide short reason.

Q: Do you use other plugging materials than cement?

10) Equipment (subsea well)

Horizontal XMT might be viewed as a better option for subsea wells from P&A point of view, as tubing can be retrieved with less effort.
Q: What type of XMT do you typically use on subsea wells?

11) P&A in Well design

PSA urges industry to increase focus on P&A when planning and drilling new wells.
Q: At what stage in well design do you perform P&A evaluation (before AFE or after)?

Q: Can you provide a figure of actual, recently designed production/injection well, that contain lithology, pore pressure and fracture gradients, chosen depth for casing seats and P&A barrier schematic?

Q: Can you comment on why casing seats were placed at these depths?

Q: Were there/are there any challenges (uncertainties) when considering P&A in the well design phase for this well?

Q: Were any casing seats or casing cement lengths adjusted to ease future P&A?

Q: Were any surface/subsea/subsurface equipment adjusted to ease future P&A?

Q: Having in mind P&A schematic of the well above, has it been already decided what equipment/rig/vessel will be used to abandon the well? For example: drilling rig will perform all P&A activities; or drilling rig will perform only part of activities while less expensive methods will be used to perform remaining activities.