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Well Integrity behind casing during well operation.Alternative sealing materials to cement

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Abstract

Maintaining well integrity during all well operations has become a major concern for operators worldwide. The maintenance of an increasingly aging well stock and the higher cost associated with new wells makes well integrity a critical element of asset lifecycle management. Factors such as wellbore instability, corrosion, cement bond deterioration, expansion/contraction, and changing pressure envelopes to name a few, all contribute to compromised well integrity. Therefore, assessing the integrity of existing wellbores is crucial for optimizing productivity and adding value.

For an oil/gas well to maintain its integrity and be produced effectively and economically, it is pertinent that a complete zonal isolation is achieved through out the life of the well. This complete zonal isolation, however, can be compromised due to factors that come into play during the operative life of the completed well. There has been a lot of research and experimental investigations in the area of well cement design and this has led to improved cement designs and cementing practices but yet many cement integrity problems persist and this further strengthens the need to evaluate alternative sealing materials to cement.

This thesis work describes the process criteria and consideration of design of wellbore seals to establish well integrity behind casing. In order to improve the primary cementing, alternative materials to cement was evaluated. An assessment of ThermaSet and Sandaband was conducted with the emphasis on applicability, placement and zonal isolation.

The assessment of the materials showed potential in both Sandaband and ThermaSet. Even though both materials had properties which made them good for long lasting isolation, cement will still be the only material for cementing in the near future. This is because of the superior ability to support the casing, the diversity of cement, low cost of the material and due to the state of the industry. The property of the alternative materials makes them possible candidates for future corrosion and temperature fluctuating wells. Sandaband can also be used as isolation behind the casing in shallow gas wells. The usage of Sandaband will be limited to simple well solution because of the complexity of the operation. ThermaSet is currently too expensive, and there are too many untested issues related to it as a primary cementing material. It is recommended that the design and material selection for sealing casing in wellbores be site specific. Evaluation of sealing effectiveness should be made on the entire seal system i.e. seal, seal-rock interface and the surrounding rock. Consequently, the experimental work presents a detailed investigation of the physical and chemical capabilities of barite loaded mud as a reliable alternative to cement as a sealing material. In order to verify how capable barite loaded mud is as an alternative to cement, a laboratory experiment that gave data as to the shear strength of the mud, how it could be handled to ensure that a long plug with high solids concentration is created, its gel strength, its density, setting time, filtration rate, and rheological parameters were studied. Comparisons were made of the test result with the properties of Portland cement. The test results showed slight agreement with the published properties of Portland cement. The results obtained from the study show that: At low mud rheology, barite loaded mud is pump-able since it pumps with gear pump at reduced pressure; too much water lowers slurry viscosity. This makes it easier to pump; however, it may lead to the following objectionable characteristics: longer setting time, reduction in ultimate strength of the cementing material. The effective density of a suitable barite loaded mud that can be used as a reliable alternative to Portland cement is 1.28kg/litre.

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1. Introduction

Given that the operational phase of a well life can last for 30 years or more, one of the biggest problems is managing the well to ensure an optimum safe condition is maintained for the whole well design life. This leads to the concept of well integrity. Well integrity management is becoming a vital element in managing corporate risk for operators. Spills and leaks through loss of integrity can harm people, the environment and a firm's reputation. In addition to the severe curtailment to production and the cost of shut-in, there is also the cost of restitution and remediation. Billions of dollars are lost each year by sporadic or ineffective well maintenance and unplanned shut-ins due to well integrity issues. In the North Sea alone, it was recently estimated that shut-ins resulted in lost revenues of more than $8 billion annually (Exprosoft, 2010). Even more difficult to estimate are damages caused by blowouts and non-catastrophic leaks to the environment, whether onshore or subsea. Even when commitment to well integrity management is high, with efforts geared toward improving the design and operational procedures during the well design and construction processes and throughout the entire well life cycle, many well integrity-related problems still occur. This indicates that investing in well integrity is a strategic approach to minimize design and operational risks that may jeopardize personnel safety, the environment, and the operator's image, reputation, and assets. (Alcantara, 2013).

History shows some severe examples of losing integrity in wells such as the Phillips Petroleum's Bravo blowout in 1977, Saga Petroleum's underground blowout in 1989, Statoil's blowout on Snorre in 2004, and The Montara oil and gas leak in Western Australia in 2009, BP's Macondo blowout in the Gulf of Mexico in 2010, Chevron rig fire in Nigeria in 2012 and more recently the Elgin Platform – UK, in March 2012. These serious accidents remind us of the potential dangers in the oil and gas industry and they are some of the main drivers for the current focus on well integrity in the industry.

Improvements in well barrier materials are now possible as are applications of sensing and cement remaining life assessment technologies developed in other industries. The use of cement for sealing a well annulus has over the last couple of centuries become an accepted industry standard and, if properly done, is also a highly efficient solution. However, a cement bond log which indicates that a good seal has been established does not necessarily ensure that this will remain effective over time. Indications are that after some years of production approximately half of all the wells will have developed leaks to a smaller or larger extent. Furthermore formations may subside or otherwise change in relation to the well or the cement as such may deteriorate due to the ambient environment and gradually change its properties which may have far reaching consequences.

Unfortunate incidents as mentioned above have serious implications caused by failing cement have increased the awareness and well integrity has become an issue of major concern amongst operators. These incidents combined with developments in harsher and more challenging areas have stimulated the development of alternative solutions, particularly for

highly deviated and horizontal well section where establishing a cement sheet in the annulus can be very difficult. This development is further accentuated by cement shrinkage, gas/fluid migration through the cement, tensile cracks and fractures in the cements plugs. The consequences of poor well integrity management relating to casing cementing can, in some cases become immeasurable. However, for the most part, good well integrity practices will maximize the life of the well, its productivity, and most importantly its safety while minimizing well maintenance costs.

The importance of well integrity has been acknowledged in the oil industry and need not be overemphasized. Arguably the most definitive statement for the role well integrity plays is from the Norwegian Petroleum Industry Standard – NORSOK D010 (NORSOK,2011). This particular standard defines well integrity as the "application of technical, operational, and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well."

It is against this background that this work is looked into. One hypothesis in the present investigation is that many of the well integrity problems stem from the fact that despite the mechanical properties of cement and its strength, it still fails with time. Therefore this work aims at looking at well integrity behind the casing during the complete life-cycle of well operations. Possible alternatives to cement would then be evaluated.

In order to achieve this aim, the work would follow the order:

- Existing definition and knowledge of well integrity
- Existing alternatives to cement in well integrity behind casing
- Testing of the alternatives with the task of evaluating their applicability in the field on the basis of their characteristics in the lab
- Engineering and theoretical evaluation of one selected integrity problem

2. Existing Knowledge on Well Integrity

This chapter focuses on the concept of well integrity as published by various authors. The study would cover a wide range of issues on well integrity ranging from the definition of well integrity, the barriers used in ensuring well integrity, the effects of loss of well integrity etc.

2.1 Well integrity—a definition

First, well integrity is defined in NORSOK D-010 (2004) as: "application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well".

NORSOK D-010 is a functional standard and sets the minimum requirements for the equipment/solutions to be used in a well, but it leaves it up to the operating companies to choose the solutions that meet the requirements. The operating companies then have the full responsibility for being compliant with the standard.

Following from this definition, the personnel planning the drilling and completion of wells will have to identify the solutions that give safe well life cycle designs that meet the minimum requirements of the standard.

Another implication is that operating companies and service providers have an obligation to ensure that the equipment planned to be used will comply with the standard and if not, the equipment will need to be improved and qualified before use. Deviations from the standard can be made in some cases when the standard allows this. If a solution selected deviates from the standard, then this solution needs to be equivalent or better compared to what the requirement is.

When selecting technical solutions, it is important to set the right equipment specifications and define the requirements for the well barrier to ensure the well integrity is maintained throughout the well life. Typical things to specify are the BOP rating and size, the casings to be used, the pressure rating on downhole and topside equipment and the material specification of the equipment. These specifications will be set at an early stage of a project and the later selection of equipment will be based on it.

Secondly, according to Cameron (2011), wells in the oil and gas industry are physical assets which connect the reservoir to the surface, and through which we produce oil, gas, water reservoir fluids and contaminants. By connecting the surface (above the sea or at ground level) with a source of energy (the reservoir pressure), it is vital that the well is designed and installed so that it provides sufficient barriers to effectively contain and control the flow of fluids resident in the formations and reservoirs which the well penetrates. Wells have a finite life, which commences with the initial drilling operation.

Thereafter, the well may be exposed to various well 'activities', such as completion, stimulation, intervention, workover, maintenance, suspension and ultimately abandonment.

Effective management of well integrity needs to consider this range of well activities as well as steady state production. Integrity is variously described in dictionaries as a state which provides veracity, reliability, honesty and uprightness; a state which can be relied on as an accurate condition at any point in the life of a well.

The following description of well integrity is offered for consideration:

'The instantaneous state of a well, irrespective of purpose, value or age, which ensures the veracity and reliability of the barriers necessary to safely contain and control the flow of all fluids within or connected to the well.'

In the views of this author, well integrity resides as a subset of a broader concept which is described as production assurance.

Production assurance encompasses such related concepts as flow assurance, well integrity and commerciality:

- 'Production assurance is the continuous optimization of production from oil and gas assets which is achieved in the following manner:
- Without harm to people or the environment;
- Delivered with technical conformance to regulatory and statutory frameworks;
- With a comprehensive understanding of the physical constraints and data constraints of the operating environment;
- Recognizes the requirement for continuous improvement in the delivery of engineering equipment and services relating to well and production activities.'

If one were to accept these definitions, then production assurance cannot be delivered without assuring the integrity of the well (and supporting production facilities). If we measure the economic success of an operator of an oil and gas production facility through their ability to deliver production assurance, then according to the definitions above, well integrity is essential, in fact critical, to good business practices and sustainability of the E&P business.

Finally, Norsk olje og gass (2011) defined well integrity as a condition of a well in operation that has full functionality and two qualified well barrier envelopes. Any deviation from this state is a minor or major well integrity issue. Common integrity issues are often related to leaks in tubular or valves, but can also be related the reservoir issues as loss of zonal control. Any factor that leads to a functional failure is a loss of well integrity. The challenge is of course to define all possible scenarios.

2.2 What can go wrong in wells?

Many different types of failures can lead to loss of well integrity. The degree of severity is also varying. For each of the blowouts mentioned above, a long chain of events led to the incidents. The simplest approach would be to consider failure of individual well components. Figure 2.1 shows some results from a PSA study conducted by Holmes (2006). Clearly the production tubing is the dominating component with failure. This is not unexpected as the tubing is exposed to corrosive elements from the produced fluids and, the production tubing

consists of many threaded connections where the high number of connections gives a high risk of leak. Two well barriers between the reservoirs and the environment are required in the production of hydrocarbons to prevent loss of containment. If one of the elements shown in Figure 2.1 fails, the well has reduced integrity and operations have to take place to replace or restore the failed barrier element.
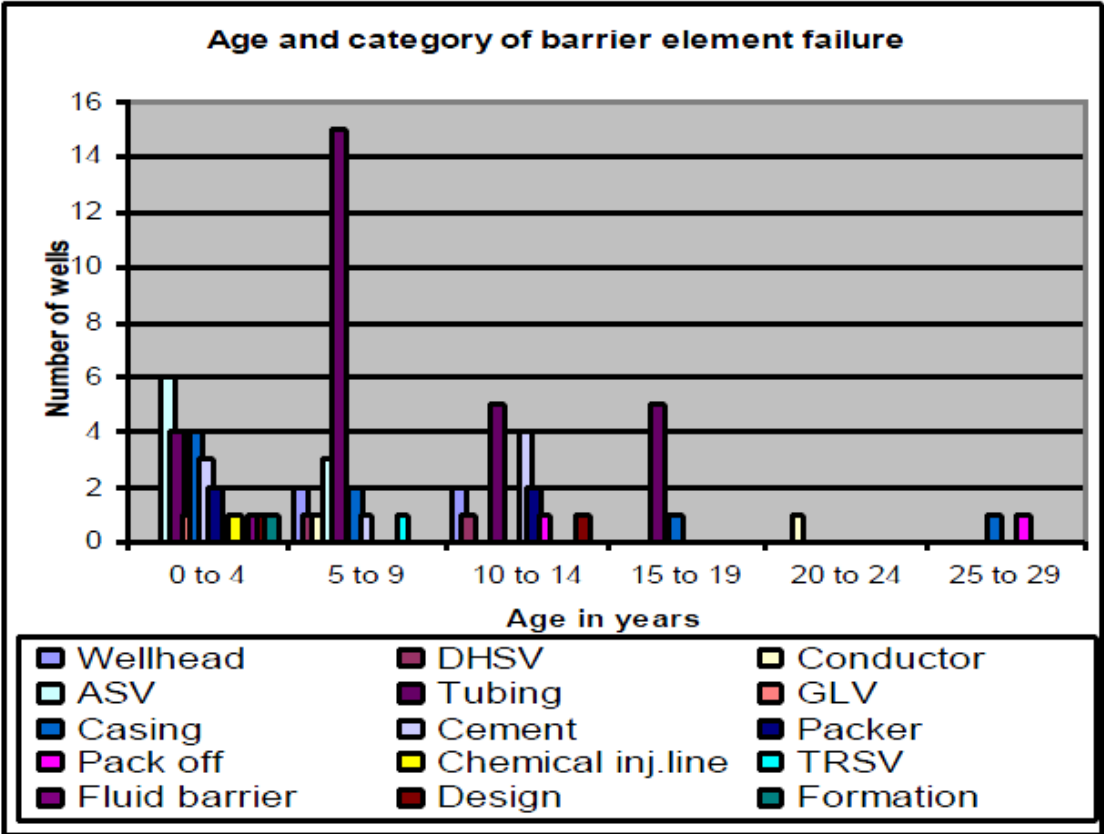
Figure 2.1: Example of failure statistics with age (Braune, 2012).

Loss of well integrity is either caused by mechanical, hydraulic or electric failure as related to well components, or by wrongful application of a device. An example of the latter is to not close the BOP during a well control incident. This shows that we must go beyond the technical aspects and also consider well management aspects. In hindsight many well incidents have become worse because of wrong decisions. Education and training therefore form an important basis for improved well integrity.

2.3 How likely is loss of well integrity?

The likelihood of a failure is connected to underlying causes. One example is a 100 year ocean wave that often is the design criterion for offshore structures. By extrapolating the wave height frequency diagram to 100 years this value is obtained. It is a statistical figure with no correlation to actual events. It gives us a mean to consider the severity of an event to the expected frequency of occurrence.

Likelihood is also important from another perspective, namely if it is realistic. How likely is it that the standby boat collides with the semisubmersible rig during a well control event? We understand that there is a compromise between the severity threshold and the number of scenarios to consider. The PSA study did not resolve the likelihood issue, but there was some information that is relevant. Figure 2.2 shows the number of wells with integrity problems from the pilot study. Of the components identified, the production tubing suffered failure in many wells. Based on the information from Figure 2.2, there is a high probability that the well will experience a leakage in the tubing during its lifetime. To reduce the risk of failure it is important to control the risk factors and to detect leakages at an early stage (before failure).
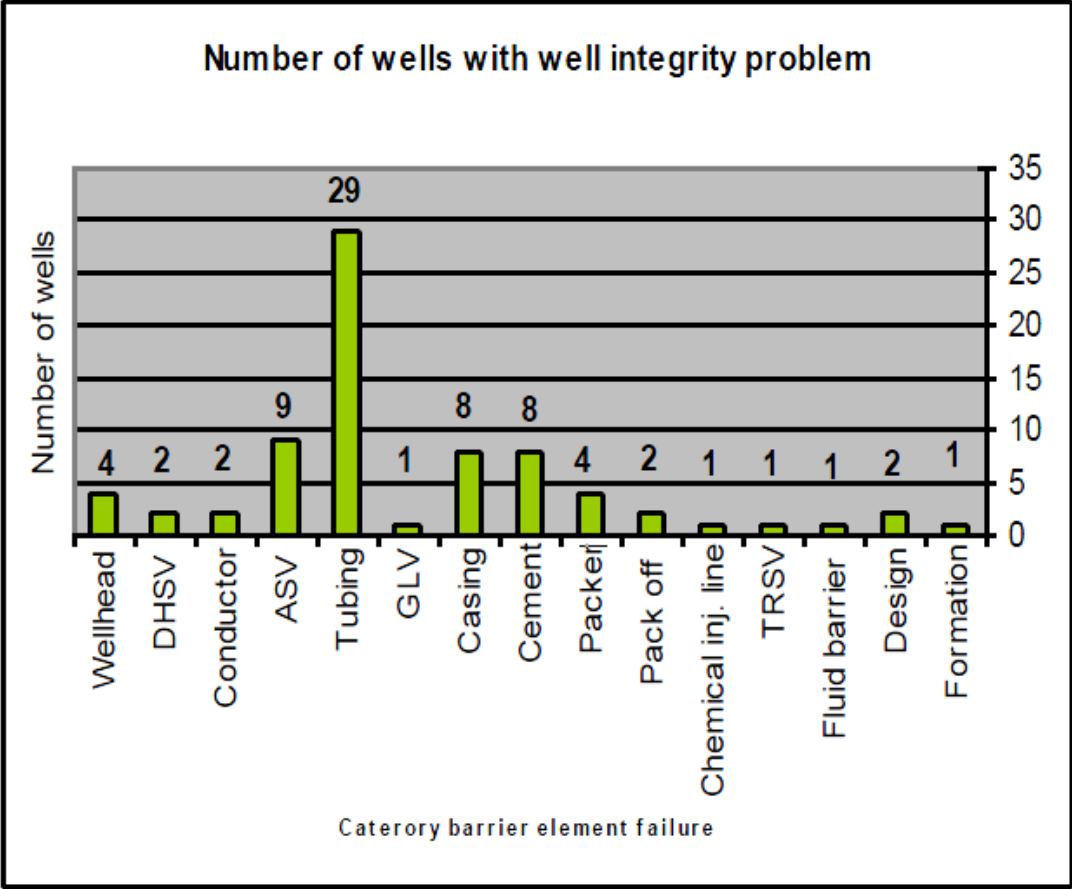
Figure 2.2: Example of barrier element failures. (Braune, 2012)

To further illustrate what can go wrong in wells, data from offshore operations in the Gulf of Mexico spanning 1992 to 2006 clearly demonstrates the significant role cement barriers play in ensuring safe and productive operations during the drilling and completion phase of a well (Izon et al., 2007). As shown in Figure 2.3, cementing failure contributed to over 50% of the well control incidents recorded.
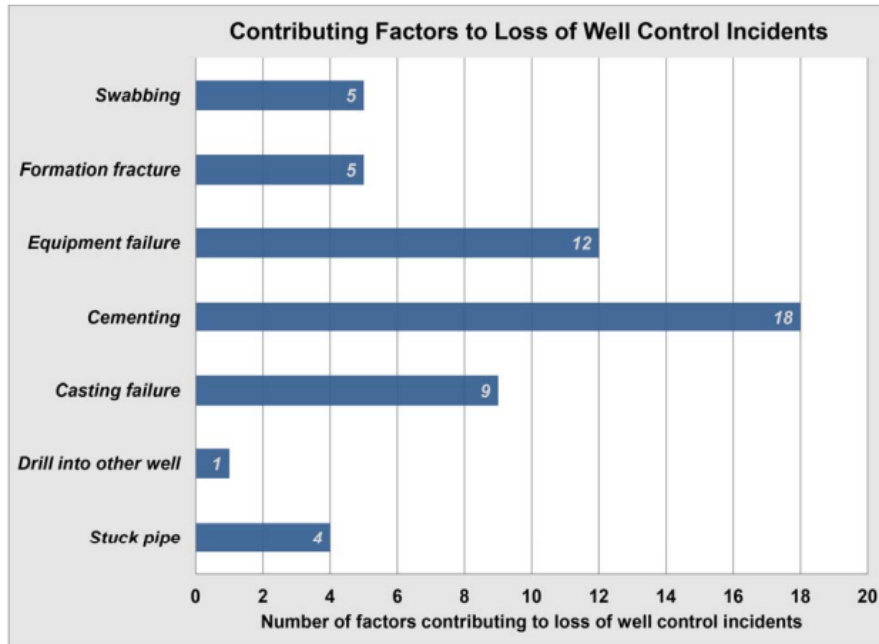
Figure 2.3: Contributing factors to loss of well control incidents in the Gulf of Mexico (Izon et al., 2007).

2.4 What are the consequences of loss of well integrity?

Well integrity has been at the forefront of oil company concerns and the general public's minds more than ever before, over the past few years. A number of serious well failures in recent years led to investigations of well-integrity issues. The Petroleum Safety Authority Norway (PSA) performed a pilot well-integrity survey based on supervisory audits and requested input from seven operating companies, 12 preselected offshore facilities, and 406 wells. The wells were a representative selection of production and injection wells with variation in both age and development categories. The pilot project indicates that 18% of the wells in the survey have integrity failure, issues, or uncertainties, and 7% of these are shut in because of well-integrity issues. The selection of wells and the companies indicate that the statistics are representative. A later study indicated that each fifth production well and each third injection well may suffer from well integrity issues.

The well incidents in the past and the results of the pilot well-integrity survey revealed that the industry needs to increase focus on barrier philosophy. Control of barrier status is an important health, safety, and environment (HSE) factor to avoid major incidents caused by unintentional leaks and well-control situations. Knowledge of well-integrity status at all times enables the companies to take the right actions in a proactive manner to prevent incidents. It is an operator's objective to safeguard lives, protect the environment and maintain production rates throughout the entire life cycle of a well at a low cost. It starts with the proper well design to fit its purpose throughout the entire life of a field, ensuring best practices while drilling, completing and operating a well. (Vignes, and Aadnøy,2010)

The consequences of losing well integrity (and subsequent well control) have been graphically demonstrated to the world. The executive summary released by BP in September following its own internal inquiry into the Macondo incident determined that the event was

initiated by "a well integrity failure." This failure subsequently led to a further chain of events that resulted in the overall catastrophic outcome. The fall-out from this incident alone could significantly change further the way well integrity is managed, now that the extreme consequences of a failure in this process have been demonstrated. (King, 2011)

The obvious consequences are blowouts or leaks that can cause material damage, personnel injuries, loss of production and environmental damages resulting in costly and risky repairs. Knowing that most of the wells in the North Sea have a large production rates, losses due to production/injection stop may be very costly. Often these losses exceed the cost of the repair of the well.

This shows that well integrity depends not only on equipment robustness, but on the total process, the competence and resources of the organization and the competence of the individual. In the following we will approach well integrity from a technical perspective, but keep in mind that any other element like a wrong operational decision may lead to well integrity issues.

According to Eventogo (2012), a well integrity incident and breach of well integrity envelope has the potential to escalate into catastrophic events. The event can result in harm to people, damage to Assets and the environment and to the reputation of the Operator.

Financial impact can be very high; loss of revenue of the hydrocarbons that escape, damage to the reservoir as a result of the uncontrolled flow and collateral damages has the potential to bring an operator in financial dire straits.

Several incidents in the recent past have shown that even the largest Operator can barely manage such financial drain. It is therefore of critical importance that the well integrity envelope is properly designed, constructed and maintained during its life cycle: Sustained Well Integrity Management (WIM).

2.4.1 Reported cases of failures resulting from loss of well integrity

Well integrity management is becoming the main mission of oil and gas operators, especially those with maturing fields. Well integrity problems have become more challenging; increased reservoir and well complexity, such as HPHT, is contributing to this. Statistics have shown that well integrity challenges are increasing. In 2004, a study conducted by the minerals management service (MMS) in the Gulf of Mexico has shown that 45% of all wells have sustained casing pressure; more recently a similar study in 2009 in the North Sea showed comparable results. Designed surveillance and/or online monitoring, and accurate diagnosis, are all essential for taking the proper action in time to resolve problems, and extend the life of the well. (Birkeland, 2005)

An interesting observation by the study of the PSA in 2006 was that old wells had few well integrity issues, but actually most problems occurred in the age group 5-14 years. These conclusions are not general but are limited to the studies referred to. All these problems led to

well shut in for some time, and in some cases the entire platform production was temporarily shut in.

It is clear from the above description that well integrity is an important safety aspect of a well. However, some of the issues are not critical, whereas some may lead to accidents. Despite these efforts, many well integrity-related problems still occur. Here we are going to give a chronicle of events that have resulted from well integrity issues.

History is replete with numerous examples failures resulting from loss of integrity in wells. The following are some of the cases.

(a) Spindletop: Texas 1901

Lucas Gusher at Spindletop in Beaumont, Texas in 1901 flowed at 100,000 barrels (16,000 m^3) per day at its peak, but soon slowed and was capped within nine days. The well tripled U.S. oil production overnight and marked the start of the Texas oil industry

(b) Santa Barbara oil spill in 1969

Location: Pacific Ocean; Santa Barbara Channel
Date: Main spill January 28 to February 7, 1969; gradually tapering off by April
Cause: Well blowout during drilling from offshore oil platform
Spill characteristics
Volume: 80,000 to 100,000 barrels (13,000 to 16,000 m^3)
Shoreline impacted: Southern California: Pismo Beach to the Mexican border, but concentrated near Santa Barbara

Details of Incident

The Santa Barbara oil spill occurred in January and February 1969 in the Santa Barbara Channel, near the city of Santa Barbara in Southern California. It was the largest oil spill in United States waters at the time. It remains the largest oil spill to have occurred in the waters off California. The source of the spill was a blow-out on January 28, 1969, 6 miles (10 km) from the coast on Union Oil's Platform A in the Dos Cuadras Offshore Oil Field. Within a ten-day period, an estimated 80,000 to 100,000 barrels (13,000 to 16,000 m^3) of crude oil spilled into the Channel and onto the beaches of Santa Barbara County in Southern California, fouling the coastline from Goleta to Ventura as well as the northern shores of the four northern Islands. The details of the incident are as follows:

On the morning of January 28, 1969, workers drilling the fifth well, A-21, reached its final depth of 3,479 feet (1,060 m), attaining this depth in only 14 days. Of this depth, only the top 239 feet (73 m) had been fitted with a steel conductor casing; the rest was to be fitted with one once the drill bit was out. After the workers pulled the drill bit out, with some difficulty, an enormous spout of oil, gas, and drilling mud burst into the air into the rig, splattering the men with filth; several of them attempted to screw a blowout-preventer onto the pipe, but against a pressure of over 1,000 pounds per square inch (7 MPa), this proved to be impossible; all workers except for those engaged in the plugging attempt were evacuated, due

to the danger of explosion from the abundant natural gas blown from the hole; finally, the workers tried the method of last resort, dropping the remaining drill pipe – almost 0.5 miles (800 m) long – into the hole, and then crushing the top of the well pipe from the sides with a pair of "blind rams", enormous steel blocks slamming together with force sufficient to stop anything from escaping from the well. It took thirteen minutes from the time of the initial blowout to the time the blind rams were activated. Only then did the workers both on the rig and in boats nearby notice the increase in bubbling at the ocean surface hundreds of feet from the rig. Plugging the well at the top had failed to stop the blowout, which was now tearing through the ocean floor in several places The spill had a significant impact on marine life in the Channel, killing thousands of sea birds, as well as marine animals such as dolphins, elephant seals, and sea lions. The public outrage engendered by the spill, which received prominent media coverage in the United States, resulted in numerous pieces of environmental legislation within the next several years, legislation that forms the legal and regulatory framework for the modern environmental movement in the U.S.).(Wikipedia, 2013)

(c) Phillips Petroleum's Ekofisk Bravo blowout in 1977

Rig: Ekofisk Bravo Platform
Date: 22 April 1977
Location: Ekofisk Field, Norwegian Continental Shelf
Operator: Phillips Petroleum Company
The Ekofisk field was discovered in 1969, with production coming on-stream in 1971, and the field has since been extensively developed. The Ekofisk Bravo platform is situated to the north of the Ekofisk field and is one of two wellhead production facilities at Ekofisk. On 22 April 1977, it was the location of a blowout and North Sea's biggest oil spill.

The Ekofisk B blowout occurred during a workover on the B-14 production well, when about 10,000 feet of production tubing was being pulled. The production christmas tree valve stack had been removed prior to the job and the BOP had not yet been installed. The well then kicked and an incorrectly installed downhole safety valve failed. This resulted in the well blowing out with an uncontrolled release of oil and gas. The personnel were evacuated without injury via lifeboats and were picked up by a supply vessel.

The initial flow was estimated at 28,000 bpd with a calculated total release of 202,380 bbls. Up to 30 to 40% of the oil was thought to have evaporated after its initial release and the Norwegian Petroleum Directorate reported a total spill estimate between 80,000 bbls and 126,000 bbls. The well was capped after seven days on 30 April 1977. Rough seas and higher than average air temperatures aided the breakup of much of the oil. Later investigations reported no significant environmental damage and no shoreline pollution. There was also no significant damage reported to the platform.

The official inquiry into the blowout determined that human errors were the major factor which led to the mechanical failure of the safety valve. These errors included faults in the installation documentation and equipment identification and misjudgements, improper planning and improper well control. The blowout was significant because it was the first

major North Sea oil spill. Also significant was that the ignition of the oil and gas was avoided and that there were no fatalities during the evacuation. (Vinnem, 1999)

(d) Saga Petroleum's underground blowout in 1989

In Dec. 1988, Saga Petroleum A/S set 244.5-mm casing at 4437 m on Well 2/4-14 in the Ekofisk area of the North Sea. Saga was drilling from a semisubmersible in 68 m of water to evaluate the Jurassic hydrocarbon potential 300 m deeper. This exploratory well was the first drilled to such a depth in the prospect. Drilling continued through the Cretaceous with 215.9-mm bits and water-based mud. A sharp transition occurred and formation pore pressure increased from an estimated 1.65- to 2.11-g/CM3 equivalent mud weight (EMW) near the reservoir top. Formation integrity at the casing shoe was 2.18-g/CM3 EMW. The hole penetrated several potentially weak formations above the objective, and while drilling near-balanced, narrow margins between influx and lost circulation were encountered.

On Jan. 11, 1989, the crew observed a 1-m drilling break at 4733 m. The well began to flow immediately. The upper annular blowout preventer (BOP) was closed and attempts were made to establish circulation with the driller's method and to bullhead, but without success. After fighting simultaneous loss and influx for several days, the bottomhole assembly (BHA) was cemented at 4700 m, and a backoff and sidetrack planned. The drillstring, however, became plugged, requiring a coiled-tubing operation to remove the obstructions. Well control was lost on Jan. 20, malting it necessary to shear the 127-mm drillpipe with 4482 m of coiled tubing inside. Wellhead pressure increased to a maximum of 70.3 MPa. An attempt was made to bullhead down the kill line but the flex hose burst at the slip joint. The well flowed for approximately 1 minute before being shut in by the fail-safe valves. The crew disconnected the riser and moved the rig off location (Frode et.al, 1992)

(e) Statoil's incident on Snorre A in 2004

The Snorre field has been producing oil and gas since 1992. Up until 1999, when Norsk Hydro took over, the field was operated by Saga. Statoil became operator at the turn of the year 2002/2003. Snorre A is an integrated production, drilling and accommodation platform anchored at a depth of approximately 300-350 m in the North Sea. On 28 November 2004, an uncontrolled gas blow-out took place on the seabed under the platform. The incident occurred in connection with the preparation of well P-31A for the drilling of a sidetrack. During pulling of a 2,578 m scab liner, gas was drawn into the well and it leaked out through a known hole in the 9 5/8" casing then through an unknown damage or weakness in the 13 3/8" casing. There were 216 persons on board at the time of the incident, 181 of whom were evacuated to other installations while the other 35 persons remained on Snorre A to carry out emergency response and well control tasks. The gas blow-out was stopped and the well brought under control the day after. No one was physically injured in connection with the incident. The Norwegian authorities under the auspices of the Petroleum Safety Authority Norway (PSA) have investigated the incident and described it as one of the most serious incidents ever in the North Sea based on the potential of the accident. (Petersen et.al,2006)

(f) BP's Macondo blowout in the Gulf of Mexico in 2010

The Deepwater Horizon oil spill (also referred to as the BP oil spill, the BP oil disaster, the Gulf of Mexico oil spill, and the Macondo blowout) was an oil spill in the Gulf of Mexico on the BP-operated Macondo Prospect, considered the largest accidental marine oil spill in the history of the petroleum industry. Following the explosion and sinking of the Deepwater Horizon oil rig, which claimed 11 lives, a sea-floor oil gusher flowed unabated for three months in 2010. The gushing wellhead was not capped until after 87 days, on 15 July 2010. The total discharge is estimated at 4.9 million barrels (210 million US gal; 780,000 m^3) (Wikipedia, 2013)

(g) Chevron oil fire in Nigeria in 2012

One of the most recent cases of failures as a result of loss of well integrity is that involving Chevron's KS Endeavour drilling rig. The well is located in the Funiwa Field approximately six miles (10 kilometers) offshore and in approximately 40 feet (12 meters) of water. Essentially the rig burst into flames. A possible failure of surface equipment during drilling operations may have caused the fire that erupted on board the jack-up KS Endeavour (300' ILC) offshore Nigeria early January 16, 2012 in which two fatalities were recorded.

In summary, all of these high profile events occurred due to a loss of well integrity either during drilling, production or work-over operations, resulting in a loss of well control. The severity of the events escalates as a result of subsequent ignition of a combustible mixture of air and hydrocarbons. Although the root causes of most of these catastrophes are yet to be formally determined, the consequence is a further blemish on the reputation of the oil industry, and ultimately will result in increased costs, scrutiny and regulation relating to the exploration and exploitation of hydrocarbons.

The increasing number of widely publicized oil and gas well failures as a result of loss of well integrity is a reminder of the engineering challenges associated with drilling activities and the importance of safety controls in well operation. All these events are summarized in Table 2.1

Table 2.1: Summary of well integrity incidents

Year	Well Integrity Incident	Region	Number Of Fatalities	Causes
1901	Gusher at Spindletop	Texas, U.S.A	Nil	Minning Engineers were mining not knowing there was oil reserve there.
1969	Santa Barbara oil spill	Southern California, U.S.A	Nil	Ruptured underwater pipe
1977	Ekofisk Bravo blowout	North sea, Norway	Nil	Down hole Safety Valve (DHSV) was not properly locked in during the work over operation

1989	Saga Petroleum's underground blowout	North sea, Norway	Nil	There was a case of casing burst in the well
2004	Statoil's incident on Snorre A	North sea, Norway	Nil	Gas leaked through damaged casing
2010	BP's Macondo blowout	Gulf of Mexico	11	Cement was not allowed to dry before running negative pressure Test
2012	Chevron oil fire	Niger Delta, Nigeria	2	Failed Blowout Preventer

2.5 Well Barriers – definitions, classification, and requirements

NORSOK D-0101 specifies that: "There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole/well to the external environment". This sets the foundation for how to operate wells and keep the wells safe in all phases of the development. This requirement is also referred to in PSA's Activities and Facilities regulation and it implies that operators have to adhere to the two well barrier philosophies and maintain sufficient adherence in all phases of their operations.

2.5.1 Key concepts and definitions

Well barriers are used to prevent leakages and reduce the risk associated with drilling, production and intervention activities. **Well barrier:** Envelope of one or several dependent barrier elements preventing fluids or gases from flowing unintentionally from the formation into another formation or to surface [NORSOK D-010].

The main objectives of a well barrier are to:

☐ Prevent any major hydrocarbon leakage from the well to the external environment during normal production or well operations.

☐ Shut in the well on direct command during an emergency shutdown situation and thereby prevent hydrocarbons from flowing from the well.

A well barrier has one or more well barrier elements.

Well barrier element: Object that alone cannot prevent flow from one side to the other side of itself [NORSOK D-010].

Some well barriers have several barrier elements that, in combination, ensure that the well barrier is capable of performing its intended function(s).

Events and situations that require a functioning well barrier are called demands. A demand can be instantaneous or continuous. An example of an instantaneous demand is a command

from the emergency shutdown system at the platform that requires response from the well barriers. A continuous demand may be a constant high pressure (that the well barrier must withstand).

As shown in Figure 2.4, there are four main ways in which hydrocarbons can leak from the system to the environment:

- Through the downhole completion tubing string
- Through the downhole completion annulus
- Through the cement between the annuli
- Outside and around the well casing system

In this work, loss of well integrity through sealing materials through casing would be considered.

Figure 2.4: Ways of losing well integrity. Red ring shows the focus of this thesis

2.5.2 Well Barrier Requirements

The performance of a well barrier may be characterized by its:

- Functionality; what the barrier is expected to do and within what time
- Reliability (or availability); the ability, in terms of probability, to perform the required functions under the stated operating conditions and within a specified time.
- Survivability; the ability of the barrier to withstand the stress under specified demand situations.

Regulatory bodies give overall requirements in their regulations, and make references to guidelines and recognized national and international standards for more detailed requirements. The Norwegian Petroleum Safety Authority (PSA) uses, for example, the following regulatory hierarchy:

- Regulations
- Guidelines (to the regulations)
- National and international standards that are referenced in the guidelines, such as NORSOK standards, ISO standards, API standards, and IEC standards.

We may distinguish between requirements that apply to barriers in general (e.g., as stated in PSA's Management Regulations, §4 and §5), and requirements that apply to well barriers in particular (e.g., as stated in PSA's Facilities Regulations, §48). The associated guidelines provide further details and give references to specific parts of national or international standards. The guideline to §48 of the Facilities Regulations, for example, refers to specific chapters of the NORSOK D-010 standard and also to specific sections of the Management Regulations.

From the guideline to §48 of the Facilities Regulations, and the referenced standards, the following requirements can be deduced:

- At least two independent and tested barriers shall, as a rule, be available in order to prevent an unintentional flow from the well during drilling and well activities.
- The barriers shall be designed so as to enable rapid re-establishment of a lost barrier.
- In the event of a barrier failure, immediate measures shall be taken in order to maintain an adequate safety level until at least two independent barriers have been restored. No activities for any other purposes than re-establishing two barriers shall be carried out in the well.
- The barriers shall be defined and criteria for (what is defined as a) failure shall be determined.
- The position/status of the barriers shall be known at all times.
- It shall be possible to test well barriers. Testing methods and intervals shall be determined. To the extent possible, the barriers shall be tested in the direction of flow.
- Separate regulations are issued by the PSA for handling of shallow gas in drilling operation. When drilling the tophole section, the gas diversion possibility is regarded as the second barrier. This is, however, not a barrier according to the barrier definition above.

2.5.3 Well integrity and well barriers

The technical means of avoiding well integrity loss are well barriers. As defined earlier, a well barrier is defined by NORSOK D-010 as "an envelope of one or several dependent barrier elements preventing fluids or gases from flowing unintentionally from the formation into another formation or to surface". The same standard defines a well barrier element (WBE) as an "object that alone cannot prevent flow from one side to the other side of itself". A well barrier can be viewed as a pressurized vessel (envelope) capable of containing the reservoir fluids. The two barrier principle is followed in Norway and in most oil producing countries. This principle means that there should be at least two well barriers in a well. A well can therefore be considered as a system of two or more pressurized vessels (envelopes) that prevent the fluid from entering the surroundings. Figure 2.5 illustrates the well barrier system as pressure vessels. In Figure 2.5, the well tubulars and the x-mas tree body constitute the vessel walls while the SCSSV and x-mas tree valves are illustrated as the outlet valves from the vessel. The innermost vessel illustrates the well barrier closest to the reservoir while the outer vessels illustrate the consecutive well barriers.

A well release will typically be an incident where the outer vessel leaks, and the inner well barrier stops the leak. In a blowout situation all the predefined technical well barriers or the activation of the same in one possible leak path have failed.

A well barrier schematic (WBS) is a static illustration of the well and its main barrier elements, where all the primary and secondary well barrier elements are marked with different colors. A well barrier schematic (WBS) is shown for a standard production well in Figure 2.5 This well has six *primary* well barrier elements:

- Formation /cap rock above reservoir
- Casing cement
- Casing
- Production packer
- Completion string (below the DHSV)
- Surface controlled subsurface safety valve (DHSV) - and six *secondary* well barrier elements:
- Formation above production packer
- Casing cement
- Casing with seal assembly
- Wellhead
- Tubing hanger with seals
- Annulus access line and valve
- Production tree (X-mas tree) with X-mas tree connection

Examples of well barrier schematics for a wide range of well situations are established and evaluated in NORSOK D-010.
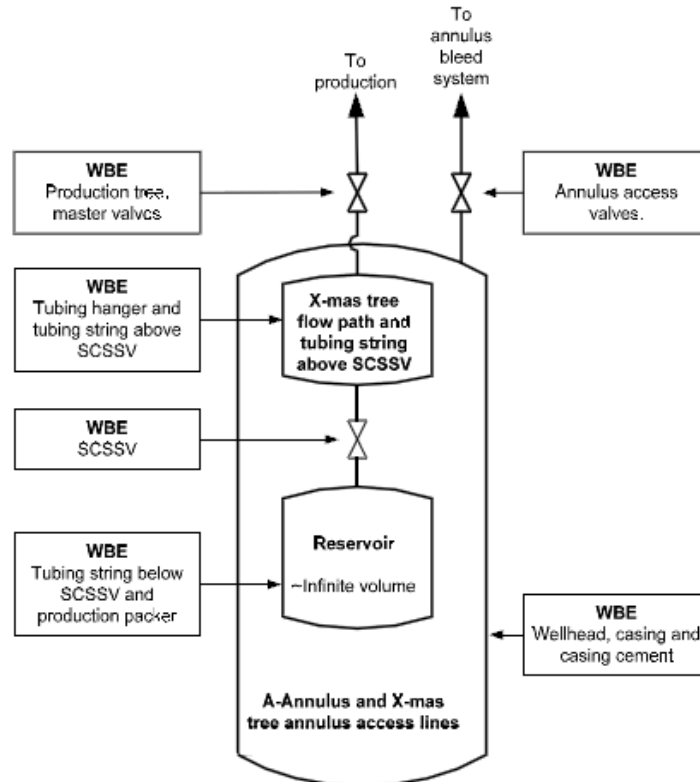
Figure 2.5: Illustration of well barriers to achieve well integrity (Source: Corneliussen,2006)

2.5.4 Well Barrier Functions

In the analysis of well barriers, it is important to understand the barrier functions and the possible ways the barrier can fail.

NORSOK D-010 distinguishes between *primary* and *secondary* well barriers. A primary well barrier is the barrier that is closest to the pressurized hydrocarbons. If the primary well barrier is functioning as intended, it will be able to contain the pressurized hydrocarbons. If the primary well barrier fails (e.g., by a leakage or a valve that fails to close), the secondary barrier will prevent outflow from the well. If the secondary well barrier fails, there may, or may not, be a *tertiary* barrier available that can stop the flow of hydrocarbons.

Barrier elements that involve electrical, electronic, and/or programmable electronic technology are referred to as safety-instrumented functions. An example of a safety-49 instrumented function is the DHSV, which is only activated upon signal from sensors or manual pushbuttons. Safety-instrumented functions are carried out by a safety-instrumented system with three main subsystems:

- Input elements; sensors (for automatic activation) or push-buttons (for manual activation)
- Logic solver(s); an electronic or non-electronic device that process the signal(s) from the input elements and send signals to the relevant final elements
- Final elements; physical items that interact with the well, for example valves, such that loss of containment is stopped or avoided.

Several safety-instrumented functions may be built into the same safety-instrumented system. The same logic solver may, for example, be used to activate several isolation valves. However, there are some important design considerations: Functions that shall respond to the same event (e.g., well kick or choke collapse) should not share components. This means that if the primary and secondary barriers have safety-instrumented functions, they need to be placed in two different (and independent) safety-instrumented systems to avoid that a failure of the logic solver causes simultaneous failure of the primary and the secondary barrier. On an oil and gas installation, there are several safety-instrumented systems with names related to their essential function: emergency shutdown systems, process shutdown systems, fire and gas detection systems, and so on.

1. Fluids as a Barrier

Only drilling mud can be defined as a truly independent fluid well barrier. It has the fundamental requirements of both overbalance and a method of sustaining the fluid column by means of the mud cake preventing the overbalance pressure injecting the fluid into the formation. Brine (or other non-particulate fluids), on the other hand, cannot be said to be an independent barrier. Brine is designed not to damage the perforation/formation and cannot "Pack off" in the same manner as mud.

When brine is used as the column of fluids which provides hydrostatic overbalance, the brine requires being isolated from the perforations to prevent it dissipating into the formation, and thus reducing the hydrostatic head. For this reason, brine and plug (mechanical or cement) which retains the brine cannot be considered as two independent pressure barriers, as the brine is completely dependent on the plug not leaking.

The brine can only be said to provide a true barrier it its level can be observed continuously to ensure maintenance of the hydrostatic head. In practice this is not normally possible, especially when an upper mechanical barrier encloses the brine column.

Discussion on fluids as a barrier: Consider the case of a lower and upper pressure tested barrier with a column of overbalanced brine held in place between the two barriers by the integrity of the lower barrier; If the lower barrier should leak then hydrostatic overbalance pressure will cause the brine to dissipate beneath this barrier towards the formation .The head of brine will continue falling until the hydrostatic overbalance disappears. It is not possible to detect /observe this fall in level without disturbing the integrity of the upper barrier.

Once of the overbalance has disappeared, then the leak allows hydrocarbons to percolate past the lower pressure barrier. Trapped below the upper pressure barrier, the only way the hydrocarbons can expand as they travel up through the brine is to displace more brine through the leaking lower barrier, exacerbating the fall in level of brine .Ultimately pressurized hydrocarbons build up undetected underneath the upper barrier.

The brine is thus completely dependent upon the lower mechanical barrier not leaking. If this lower barrier remains leak tight then it contains the well pressure satisfactorily and there is no need for a supplementary barrier.

Taking the argument to its extreme, the brine in this situation appears not to provide any significant increase in safety benefits above the existing mechanical barriers.

In evaluating the role of brine as a barrier, the main argument in its defence is that the leakage past the lower plug would probably take some considerable time before overbalance was lost. Certainly this timescale could have consequences for the integrity of Sub-sea barriers, where by the very nature of the operation all barriers shall be capable of providing long term integrity. A certain "level of comfort" appears to be derived by having circulated an annulus and tubing contents to brine. From the above argument brine is clearly not an independent barrier and thus does not provide a "third" barrier as is often suggested.

If only the tubing contents were to be displaced to brine, leaving the annulus remaining with, say inhibited sea water, then this would be a clear case of dual standards in respect of barriers for the tubing annulus.

A justification exists for using overbalanced brine with some wireline plugs to assist the lower mechanical barrier in the tubing, as there may be the need to energize the "Vee" packings in wireline plugs. The latter require a differential pressure to maintain the seal is energized in the opposite direction to the formation, i.e. from above only. Secondly the seal systems on these plugs are not symmetrical and thus sealing from above is not a good indication of pressure integrity from below.

2. Mechanical Barriers (Completed Well)

Only the deepest set mechanical barrier can be truly leak tested in the direction of formation pressure .The upper, mechanical barrier therefore can only be tested from above, unless tubing/annulus communication exists above the bottom barrier.

In the case of only being able to pressure test the upper barrier from above, the sealing mechanism between the mechanical barrier and the tubing (and the sealing mechanism between any bleed-off device and the mechanical barrier) shall have symmetrical seals so that a pressure test from above is a good indication of pressure integrity from below.

NOTE: A two way check valve should not be used in this case as a test from above does not indicate that it will hold pressure from below, the sealing faces being different for each direction of flow.

Discussion on mechanical barriers

The mechanical pressure barriers in the annulus consist of the lower packer and upper tubing hanger/ wellheads seal .These mechanical barriers (packers) are set under as near ideal conditions as can be achieved down hole. Tubing hanger seals /wellhead seals are now designed to provide metal to metal sealing as the primary seal. There is a high level of confidence in both barriers ability to contain well pressure and remain leak tight as during the operation of the well they have been tested (monitored) over a considerable length of time.

The "quality" of the mechanical pressure barriers set in the tubing should ideally give the same degree of confidence in their ability to remain leak tight and contain well pressure.

There appears to be no documented evidence on the subject of long term integrity of wireline plugs for use as mechanical pressure barriers in tubing and therefore personal experience, etc. has been used in any discussion on the subject to date. Subsequently this topic was reviewed during two QRAS on barriers Requirements, and subjective reliability figures used. The result of these QRAs was to convince the HSE (who had queried our adoption of two barriers as our standard, instead of their stated requirement for three), that indeed two independent barriers, if properly tested, was the optimum.

For general purposes, and longer term suspension programmes in particular, especially in sub-sea wells, a retrievable packer/bridge plug system is preferred, as with these systems energy is locked into the seal system by virtue of the setting operation .A standard wireline plug system using Vee packings, relies on the seal being maintained by pressure differential.Wireline plugs using module seals are available for TFL completions, but require pressure assistance to install. The seal still relies on differential pressure and may be difficult to retrieve.

Retrievable bridge plugs have been developed and used successfully as both a lower and upper mechanical pressure barrier in the tubing string. These retrievable plugs are considered to be capable of providing a long term barrier.

Communication between annulus and tubing in a completed well

If the integrity of the bottom pressure barrier is confirmed then communication between annulus and tubing above this bottom barrier does not require any extra barrier over and above the second upper barrier.

The concept of "two pressure vessels" is maintained with reservoir pressure contained by:

1. The lower line of defence comprising the integrity of both the packer in the annulus and the mechanical pressure barrier in the tubing.
2. The upper line of defence comprising the tubing hanger/ wellhead seals (and side outlet valves) in the annulus and the upper mechanical pressure in the tubing

In this case the upper mechanical pressure barrier in the tubing can be pressure tested from below via the communication with the annulus.

3. Sub-surface Safety Valve as a Well Barrier
A Subsurface Safety Valve (SSSV) may be used as a well barrier provided

1. The SSSV is leak tested and confirmed leak tight.
2. The tubing integrity from the packer to the SSSV is satisfactory and confirmed leak tight, and
3. The SSSV is inhibited from opening by isolation of the hydraulic control and balance lines.

The SSSV is designed to retain the maximum differential pressure across the valve that may be generated in a well .This differential is normally seen during routine testing. Prior to being installed in a well, the SSSV is tested onshore to its working pressure. Having proved the SSSV to be leak tight in the well, then should pressure increase below the SSSV this will assist the sealing mechanism of the valve. The SSSV is designed to retain pressure across the range of temperatures observed in a well. This is applicable to both the metallic parts and the

elastomers. In the case of a wireline Retrievable SSSV of a wireline Retrievable SSSV, the mode of retention of the SSSV in the nipple is fundamentally the same at the mechanical retention of a wireline plug set in a nipple .The ability to remain set in the nipple is tested during the leak test. A Tubing Retrievable SSSV is designed and installed as a part of production tubing completion .Thus there is no potential to move up-hole under application of differential pressure. The type of SSSV (Ball or Flapper) has a bearing on the reability of the valve to remain sealing:

Ball Valve

In the case of a Ball Valve isolating the accumulator from the balance line positively prevent the ball rotating and hence maintains the seal integrity .Any flow of fluid down through the valve ,lifting it off its seat, will be temporary ,and any reversal of flow /pressure will immediately reseat the ball.

Flapper Valve

In the case of flapper valve, unlike the ball, there is no certainly that the flapper will remain our reseat once differential pressure is removed – The spring which induces flapper closure cannot be relied on the same way. Thus, a flapper valve should not relied on as a barrier where there is the possibility of it being unseated, e.g. by pressure reversal or a dropped object. The argument that a flapper valve is of no use as an emergency device (its prime function in life), does not follow , as the valve will close an a flowing well situation irrespective of spring action ,where fluid dynamics will ensure the flapper moves the closed position once the protective sleeve moves up. This is also the case for a well suspended with the Xmas Tree installed, where a flapper valve is the normal safety device that would be installed during the production phase of the well.

In considering the case of an SSSV that is used as a barrier, the problem that arises of how one can leak test the surface barrier, e.g .the tree or a retrievable bridge plug, This arises as once cannot easily trap pressure between the SSSV and surface with a chance of observing meaningful flow through the barrier, except in a gas environment. In this case its considered acceptable to adopt the following procedures:

1. If a Xmas Tree Valve is to be used as the surface barrier, then first leak test the Tree Valve, open it close and leak test the SSSV, and then close the Tree valve. Due to the high reliability of gate valves this procedure is acceptable.
2. If a plug is to be used as a surface barrier, it must be of a type that a pressure test from above gives assurance that the plug will hold pressure from below First close and leak test SSSV, and then set and pressure test the plug.

In both cases, leave the pressure differential across the SSSV, i.e., do not equalize. This ensures that work is carried out in a situation where there is no pressure below the top barrier.

If the SSSV is found not to be leak tight when tested, then either a replacement SSSV may be run and tested, or a wireline plug may be set in the nipple profile, in that its seal bore is known to be in good shape (being in continual use for the SSSV) and that the condition of this upper nipple profile with regards to erosion and sealing is generally found to be significantly better than on deeper nipples.

Using the SSSV as the top (secondary) Barrier

When proposing/ accepting an SSSV as a barrier, one must consider the potential mode of failure in the particular application. Unseating and re- sealing of the valve has been considered above. The other prime failure mode is due to impact of a dropped object. Primarily a wireline tool string past the Xmas Tree valves with the BOP/ Lubricator removed) , then the valve is directly exposed to the possible impact if the string were to be dropped . This possibility is real, and it has happened, even recently.

The consequences are likely to be different for Ball and Flapper types valves .A flapper valve is likely to shatter , and toolstring and debris will fall into the lower plug, not only causing and awkward fishing problem, but possibly compromising the integrity of the lower barrier. For this reason a flapper valve is not generally acceptable in this relative position. On the other hand a valve type SSSV is known to be extremely robust, and attempting to shatter the ball in a failed valve to gain access to the lower part of the well has caused great difficulty .The sealing ability of the ball after such as impact is likely to have been impaired, but it will still provide an availability of the tree valves this provides sufficient confidence to consider the arrangement acceptable practice. Use of the technique should still be treated with caution, especially in high pressure situations, and in particular gas wells.

In order to use a Flapper type SSSV as the top barrier when removing the BOPs / tree, it is therefore necessary to use, e.g. a TWCV, as a debris barrier. This is also good practice for Ball type SSSVs in that any debris that would otherwise fall into the well during the Tree/Bop removal process may be recovered easily, as well protecting SSSV from impact damage .Note that the TWCV may provide additional isolation security but it can NOT be relied on formally to act as a barrier

2.5.5 Reliability analysis of well barriers

The term reliability conveys failure-free operation and confidence in the equipment. Formally, reliability is defined as the ability of a system to perform its intended functions, under given environmental and operational conditions and for a stated period of time (IEC 600050-191). The ability can be studied qualitatively, for example by identifying the combination of component failures that may lead to system failure, or quantitatively, by calculating the probability or frequency of system failures.

In the context of well integrity, we will introduce reliability analysis methods that can be used to identify and assess the impact of failures of well barrier elements. Such analyses are useful for:

- ☐ Comparing different well completion alternatives with respect to blowout probabilities
- ☐ Evaluating the blowout risk for specific well arrangements
- ☐ Identifying potential barrier problems in specific well completions
- ☐ Assessing the effect of various risk reduction methods
- ☐ Identifying potential barrier problems during well interventions

After many incidents and accidents in relation to well integrity, more focus has been directed towards assessing the reliability of well barriers. The purpose of this section is to describe some of the methods that can be used to analyze well integrity – qualitatively as well as quantitatively. To be able to perform quantitative analysis it is necessary to have a background in system reliability theory. The quantitative part is therefore limited to giving a small practical example with basis in available well performance data. To give a thorough basis for system reliability theory is outside the scope of this compendium. Readers who want to get a deeper understanding of this subject may consult Rausand and Høyland (2004) or some other textbook on reliability theory.

2.5.6 Analysis steps

A well barrier analysis should be structured and may include the following steps:

1. Define and become familiar with the system.

   This step includes the definition of the operational situation, review of well schematics, construction of barrier diagram, and listing of barriers and their barrier functions.

2. Identify failure modes and failure causes

   The main method for failure identification is the failure modes, effects, and criticality analysis (FMECA). The objective of the FMECA is to identify all the failure modes, their causes, and effects for each of the barrier elements of a well barrier system.

3. Construct a reliability model of the well barrier system

   There are several alternative models available, and the choice of models should be based on what type of system states we want to study and the access to relevant data to support the models. We recommend, however, fault tree analysis, since this method is intuitive and easy to understand (at least for the qualitative parts) for those who do not have a background in system reliability theory. A fault tree is a graphical model that illustrates all the combinations of failure events that may lead to a system failure (i.e., leakage to the surroundings). The fault tree is easy to establish from the well barrier diagram.

4. Perform a qualitative analysis of the fault tree

   All the information about the causes of system can be summarized in the *minimal cut sets* of the fault tree. A minimal cut set is (a smallest) combination of failure events that may give a system failure. A system failure occurs when all the failure event of a minimal cut set occurs, and minimal cut sets with few failure events are therefore more important than minimal cut sets with many failure events. Algorithms for identification of minimal cut sets are available. With basis in the minimal cut sets, we can discuss issues such as critical components or elements, vulnerability to common cause failures. This type of information may be useful when planning well operations, well barrier maintenance, and training of personnel.

5. Perform quantitative analysis of the fault tree

By combining reliability theory and reliability data with a fault tree, we can determine a number of reliability parameters of interest, for example the probability of primary barrier failure, failure rates for primary and secondary barriers, time to first failure of primary and/or secondary barrier, and so on.

System reliability analysis is based on statistical models and methods. This means that the results are subject to uncertainty, due to modeling assumptions, adequacy of data, and the spread in possible outcomes that follows the distribution of, e.g., time to failure that is recorded for similar systems and components.

6. Report results

It is important to document all results, including assumptions and limitations that have been made. Recommendations that require further follow-up, whether it points back to necessity to redesign or to update planning, operating, or maintenance procedures need to be sufficiently highlighted. Recommendations should always be assigned responsible persons or departments.

2.5.7 Achieving well integrity behind casing using cement

During the drilling phase, well integrity is mainly associated with keeping the formation under control and ensuring that the casing used is suited for the well, so that the forces exerted on the casing string do not compromise its integrity. Examples of such forces can be collapsing formation, thermal expansion of fluids trapped in the annulus or dynamic loads experienced during run in hole of the casing. Casing wear caused by long time drilling and rotating in the last set of casing is also something that will affect the well integrity if not taken into consideration during the design phase. Casing wear is something to be particularly aware of when drilling long horizontal wells were the drill string will wear on the casing for an extended period of time.

Casing cement used as a well barrier is an extremely important well barrier element as this has to act as a well barrier element throughout the operational phase and later when the well is permanently plugged and abandoned. In order to ensure integrity it is crucial that the cement is bonding to the formation with integrity, as well as to the casing. To verify that the cement is bonding to the casing without channels, two logging tools are needed. These tools are typically cement bond log (CBL) and a sonic tool (USIT). For wells that are permanently abandoned it is important that such logging is performed to verify the integrity before the inside cement plug is set for permanent abandonment. For wells in operation it is critical to log the cement if the casing cement is acting as both the primary and secondary barrier, due to the fact that a pressure test of the cement will not verify the integrity of the cement except at the csg shoe depth, Figure 2.6. The distance between the primary and secondary barrier must also be evaluated, such that any risk of formation collapse does not crack both the primary and secondary cement column.

According to NORSOK D-010 the cement barrier must have the following properties:

a) Impermeable

b) Long term integrity

c) Non-shrinking

d) Ductile – (non-brittle) – able to withstand mechanical loads/impact

e) Resistance to different chemicals / substances (H2S, CO2 and hydrocarbons)

f) Wetting, to ensure bonding to steel.
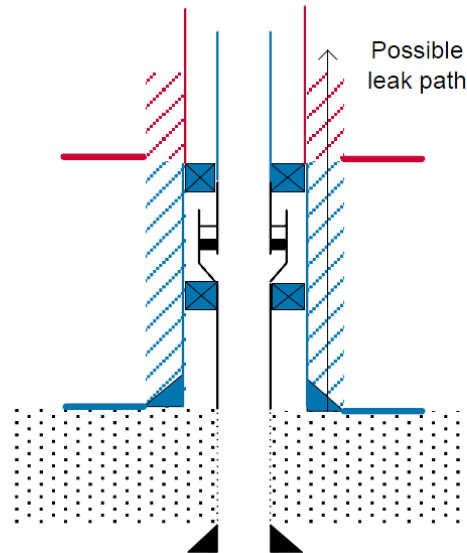
Figure 2.6: casing cement acting as part of both the primary and secondary well barrier. Braune, 2012.

The integrity of the casing cement is tested through a pressure test after drilling out the shoe. This test is typically an FIT test. To ensure sufficient cement height, it is usual to place double the required cement volume. The required cement height is dependent on the pressure, but some minimum cement heights are normally required as given in NORSOK D-010. The casing cement is acting as a vertical barrier, not a horizontal one, so it is the vertical height that needs to be assessed when deciding the volume of cement to be placed.

2.5.8 Formation replacing casing cement

The formation may also in some cases replace casing cement as barrier element. It is a well-established fact that some rock has the ability to creep, due to their plastic properties. The best known example is deeply buried rock salt, but also other formations, like clay, has this property. The plastic properties allow clay to creep into the wellbore where it is no longer held back by the pressure exerted by the mud column. Over time the formation may bond onto the casing and form a barrier against flow outside the casing.

Clay as barrier material has some benefits compared with cement: It is natural part of the succession, it is inert to chemical corrosion and it is ductile.

If you need a barrier and for some reason casing cement is not present, formation creep may provide you with a good alternative. However, this is only possible if you are able to prove bonding and pressure integrity.

Confirmation of formation barrier replacing casing cement:

☐ The interval must have a formation stress higher than the pressure it can be exposed to, which typically is the extrapolated reservoir pressure.

☐ The same requirement as for cement applies for the interval length of bonded formation.

☐ Two independent logging tools must be run inside the casing and both verify the formation bonds against the casing. At present a cement bond log (CBL) and a sonic tool (USIT) have been the preferred logging tools.

☐ If the logged response is indicative of bonding formation, then a pressure test through perforation might be required. This could possibly be done by testing the logging response for all new formations with a LOT through a perforation at least 5 m above the base of the bonded interval. The stable pressure during the shut-in phase of the LOT must be above the required pressure the barrier is to withhold.

2.5.9 Recipe for Well Integrity

According to Nolan (2012), to serve up a well with integrity, follow this recipe:

- Planning – No such thing as too much planning
- Ingredients – One bad ingredient can spoil the well
- Team – A coordinated broad based team effort is essential
- Technique and Execution – Plans and guidelines must be fit for purpose and followed – no shortcuts
- Sample – Ensure key well parameters are met along the way

2.6 Well integrity during wellbore operations

In the life of an oil/gas well four phases can be discerned, two of which are vital for the integrity of the sealant namely: the well construction phase and the production phase.

A) *Design Stage:* This involves exploration activities before actual wellbore operations begin.

B) *Well construction phase*:
- Drilling
- Cementing
- Completing

During this phase, the stresses around the bore hole, and hence the resultant wellbore stability, will constantly change due to fluctuating gravity of the fluids inside the wellbore. These processes will influence the resultant stresses in the cement sheath.

C) *Later operational phase*

During this phase, the intended operational regime of the well and planned/unplanned human interventions will seriously affect the integrity of the sealant.

Typical examples during this latter phase (which constitutes the greatest part of the life of the well) are:

- Naturally developing stresses
  Subsidence
  Depletion
- Operational Regime
  Moderate versus HPHT operation
  Water/steam injector/gas storage/production
- Human interventions
  Changing fluids
  Pressure testing
  Perforation
  Production
  Injection
  Propped hydraulic or acid fracturing
  Hot oiling
  Sidetracking operations

D) *Abandonment phase:* This stage involves plugging and abandoning wells which have reached its economic life.

Ideally, during the drafting of the Well Functional Specifications, the extremes in well operation should be defined. Next, the impact, not only on casing or tubing design, but also on the integrity of the well sealant should be evaluated.

2.6.1 Well Integrity at the Design Stage

The primary challenge at the well design stage that needs careful consideration is reliability of information relating to subsurface pressures and heterogeneity. Most wells, especially wildcats, possess a degree of uncertainty with regards to their pore and fracture pressure prediction, borehole stability expected geothermal temperature, lithology and fluid types. Among any number of offset wells drilled within a reasonable distance in an area, the age variance can be considerable, and the quality of data gathered will affect the accuracy of the subsurface predictions. For the geosciences team, fulfilling their primary function, the many uncertainties are accepted in a probabilistic approach to likely reserves. However, for the engineer, the probabilistic approach to pore pressure, fracture pressure prediction and formation properties inevitably means we must be prepared for the low possibility, high impacting event in our design.

Conventionally, during the design phase, well barriers often are designed primarily for drilling static and dynamic loads due to the complex nature of the subsurface and achieving the first priority of reaching total depth casing the section under demanding conditions. This heavily weighted focus on the drilling static and dynamic loads can have a negative integrity effect, since barriers selected are not necessarily designed for the full range of load scenarios that can arise in the production, and abandonment phases.

2.6.2 Well Integrity during drilling Operations

Drilling activity starts with spudding and concludes with preparation of the well for testing, completion or suspension/abandonment. The drilling activity could impact wellbore stability, casing integrity and the cement integrity. Key Performance Indicator (KPI's) for the well construction stage are dominated by time factors which are often misaligned with life cycle well integrity. The one constant visual indicator success is the, time depth curve. Rarely are other performance measurements, such as quality, or design verification, given daily or 'by-phase prominence in communication of progress during construction. During well construction, the actual subsurface environment is seldom what is typically expected and planned for. Prediction, and actual deficits, in pore pressure, rock strength, reservoir fluids, rock properties, formation tops and lithology types, all contribute to load boundary shifts in the "as built" from those assumed at the design stage. Often, this load boundary change is accepted without verification of the original design due to time based KPI's. The primary purpose of the well is to ensure the safe and reliable production of fluids to surface, under the range of boundary conditions anticipated for the life cycle. During construction, controls should exist at each phase, pre and post cementation, and the well completion stage, which verifies the original design, is still valid.

During drilling, the primary pressure barrier is the fluid column. The drilling mud also forms a filter cake to prevent wall collapse. Keeping the borehole wall intact ensures that the cement column would be properly set during completion. Borehole cave-ins result in an under-reamed hole which could affect the cementing operation.

Drilling through complicated geological formations requires reinforcement of the well to avoid leakage to the surface or surrounding formations. The cementitious well barrier must adequately bond to the steel well casing and the surrounding formation and maintain structural integrity throughout well exploration, production, and after abandonment. Grout mix design is not a trivial engineering task, and many new admixtures have been developed precisely for these applications. Yet, according to a "pilot well integrity survey" published in 2010 in the *Society of Petroleum Engineers (SPE) Production & Operations Journal*, 18% of the wells in the survey had integrity failure, issues or uncertainties. The survey, conducted by the Petroleum Safety Authority Norway (PSA), concluded that there needed to be "more focus on barrier philosophy to avoid major incidents caused by unintentional leaks and well-control situations." (Perricone, 2012)

There is higher risk of compromising the casing integrity during drilling operations. Prior to landing, all components of casing string including connections, circulation devices and landing string shall be subject to load case verification. For through-tubing drilling operations, the tubing and accessories shall be reclassified to casing and redesigned to meet drilling loads (NORSOK, 2004).

The following points should be considered in casing design (NORSOK, 2004):

   a. **Setting Depth**
      - Maximum allowable setting depth with regards to kick margin

- Estimated pore pressure development
- Estimated formation strength
- Drilling fluids and cement program
- Loads induced by well services and operations
- Setting depth restrictions due to formation evaluation requirements
- Potential for H2S and/or CO2
- Metallurgical considerations
- ECD and surge/swab effects due to narrow clearances
- Isolation of weak formation, potential loss zones, sloughing and caving formations and protection of reservoirs
- Geo-tectonic forces applicable

b. Casing Design factor
- Planned well trajectory and bending stresses induced by doglegs and curvature
- Estimated temperature gradient
- Estimated casing wear

Incident scenarios during drilling which could serve as basis for estimating expected loads should include occurrence of gas kick and dynamic loads from running of casing, including overpull to free stuck casing, inflow or fluid loss while running or pulling string, presence of solids/sands, presence of H2S, hydrates, wax and emulsions. When hydrates, wax or emulsions are present, contingency measures could be to supply heat to the affected area or inject suitable chemical inhibitors. It should be noted that heating the affected area results in thermal loads while injection of suitable chemical inhibitors results in higher internal pressure.

The quality of the cementing operation is also crucial in maintaining wellbore integrity.

The most widely used cements in the petroleum industry are the Portland-type cements. When it is properly set, the cement slurry can become a nearly impermeable and durable material. Cement bonds to rock by a process of crystal growth while cement bonds to casing by filling the pit spaces in the surface of the casing.

Good quality cementing will likely protect against cement degradation and casing corrosion. In a CO2-rich environment, Portland cement is known to be thermodynamically unstable. It tends to strongly degrade once exposed to such acid gases, by reacting with calcium hydroxide formed from hydrated calcium silicate phases. An EOR site where cements and casing were exposed to carbon dioxide for 17 years (Sacroc reservoir) showed that cement can retain integrity for some decades (Carey, 2005). It should be noted that the temperature in the Sacroc reservoir was only ~50°C.

In another simulation of downhole conditions for both wet supercritical CO2 and CO2-saturated water, an alteration of 100mm after 20 years of CO2 attack is possible in Portland cements. Non-Portland based cements (calcium phosphate cement – Thermalock TM) which contain aluminum hydrates, calcium phosphate hydrates and mica-like aluminosilicates are

now used as alternatives in carbon dioxide injection wells, sour-gas disposal wells and geothermal wells with high carbon dioxide content.

An alternative is to use fortified Portland cement where resistance is increased by adding a latex diluent of a specific particle size and adding a non-standard, high alumina cement to reduce the amount of Portland cement. This has been used in the well completion design for acid gas (65% hydrogen sulfide, 35% carbon dioxide) injection over a 50-year period in Labarge area, Wyoming (Benge, 2005). Relevant cement additives that help to maintain well integrity include hydrazine which is used to control corrosion of the casing and radioactive tracers to assess where the cement has been placed. (Barlet-Gouedard et al, 2006).

Besides the cementing material, the placement of cement is also important in maintaining the wellbore integrity. It is very important to do a thorough clean out of the well prior to cementing in order to prevent mud mixed into the cement causing cavities or channels. This will not only degrade the strength of the cement, but can also create leakage pathways for CO2. Well deviation can affect cement as cement sets differently in deviated wells and vertical wells. Drilling mud is first circulated in the hole to ensure that cuttings and borehole wall cavings have been removed before running the casing. The mill varnish is also removed from the surface of the casing to ensure that the cement will bond to the steel surface. Centralizers are then used to ensure that the casing is placed in the center of the borehole. For under-reamed or washed out holes, bow spring centralizers are used. After the cement slurry is pumped downhole, a lighter drilling mud follows. In this way, the casing is under compression from a higher differential pressure on the outside of the casing. Thus, when the cement sets and drilling or production operation continues, the casing will always have an elastic load on the cement-casing interface.

This elastic load is considered essential for maintenance of the cement-casing bond and to prevent leakage between the cement and casing.

Sixty to seventy percent of the wells in the Gulf of Mexico are affected by sustained casing pressures (SCP). The main cause is believed to be gas flow through the cement matrix. This could be due to gas flow through unset cement and due to cement shrinkage after completion. Remediation which included injection of high density brine in the annulus and pumping of high density fluid into the casing have little success (Crow, 2006). This problem has also been observed after routine well pressure tests. In summary, the cementing problems that could cause SCP include: (1) micro annuli caused by casing contraction and/or expansion (2) channels caused by improper mud removal prior to and during cementing (3) lost circulation of cement into fractured formations during cementing (4) flow after cementing by failure to maintain an overbalance pressure (5) mud cake leaks (6) tensile cracks in cement caused by temperature and pressure cycles (Sweatman, 2006).

2.6.3 Well integrity at the production operations stage

Historically, the production phase of a well is usually associated with the most number of Well Integrity issues. Naturally, the production phase introduces fluids which induce corrosion risk, thermal and pressure loads not seen during construction, and of course the

longevity effects of exposure. The design and construction wells are the responsibility of the drilling department to the point of handover, and well specific knowledge largely remains in the domain of the drilling department. Unless a proper handover between the functional departments have taken place, transfer of well knowledge will be inadequate. Production operators need to have a clear understating of well specific integrity issues to manage the well safety. Often, their knowledge is inadequate due to poor training and evaluation on subjects such as well architecture, annular pressure behaviour, and effective maintenance. Recently the authors trained over 500 operators in a complex series of six platforms in the Caspian Sea. The experience of 99.9% of the operators was that they had no prior training in basic Well Integrity Management. To better protect production operators and reduce the number of integrity problems in production, threats should be assessed and mitigated at the design stage and then re-validate during construction. This more focused approach to life cycle integrity would result in more reliable well handover to production and less risk to production operators and assets.

An example of a poorly managed annulus due to no operator training in WI on a high pressure well is presented in Figure 2.7. by Stuart et.al, 2010. According to them, the actual conditions at handover did not identify a low top of cement depth, a number of bleeds performed on the annulus during the construction phase, the type of bled fluids, and the volumes of fluid bled if any. Discussions with drilling staff revealed that sustained casing pressure caused by failed cement jobs, followed by sustained casing pressure during subsequent drilling were common during the construction phase. Post-handover, the well-produced with high thermal swings and repeated shutdowns due to poor plant reliability. Flow heated up the annuli fluids of the A, B and C annulus with the B annulus experiencing a pressure build-up effect greater than 400 psig.

Subsequently over the next 100 days a series of bleeds were performed on the B annulus whenever the annulus pressure exceeded 500 psig. Suspicion then arose that the pressure in the annulus was sustained, which meant that the pressure anomaly observed at surface was due to a direct communication with the formation or a casing leak rather than unsustained thermally related pressure build up. This led to the decision to allow the pressure build up to stabilize before a better assessment of the B annulus characteristic could be made. Before the annulus pressure was able to stabilize, the well had to be shut down for operational issues, which removed the thermal effects of the producing hydrocarbons. The loss of the thermally inducted effect caused the annulus pressure to reduce, however by this time, multiple bleeds on an open shoe annulus had replaced annulus fluids with a lighter density than the original mud. On re-start up the buildup pressure exceed the previous trend due to the lighter column, causing stabilized pressures much closer to MOASP.

Permanently resolving annulus pressure problems like the B annulus of the example well is operationally complex and expensive. Due to the multiple bleeds that had been conducted on the annulus since the handover, with no recorded volumes, the expected amount of formation fluid invading the annulus was unknown. Thus, the actual type of fluid composition and effective hydrostatic pressure was also unknown. Give the slow pressure build seen from Figure 2.7 below, it could be that the type of invading fluid was unlikely to be gas, and

more likely to be either formation water or oil. Sustained casing pressure in fluid filled annuli is difficult to resolve since a lubrication technique is not possible.

Due to the complexity of the subsurface environment in the example, poor cementation caused open channels created by the wells network which created pathways where reservoir fluids charged up shallower formations, creating a situation where the actual pore pressure at the B annulus shoe was unknown. Since the annulus fluid density degrade over time, the SCP was climbing and the thermal effect on the annulus was dramatic during the start up process. Poor understanding of the phenomenon, allowed the operators to bleed off the annulus further removing quantities of annulus fluid, by drawdown and induction of formation fluids. As shown in Figure 2.7 the annulus pressure eventually stabilized at around 1100 psig. At this pressure, the well had to be dispensed and managed through reduction in production rate, to keep the B annulus SCP below MOASP (Maximum Operational Annulus Surface Pressure). The rate allowable was 15,000 BOPD instead of the usual rate of 30,000 BOPD. If well integrity and operator training had been given due consideration during the well design, construction, and handover to production, significant loss and risk could have been avoided.
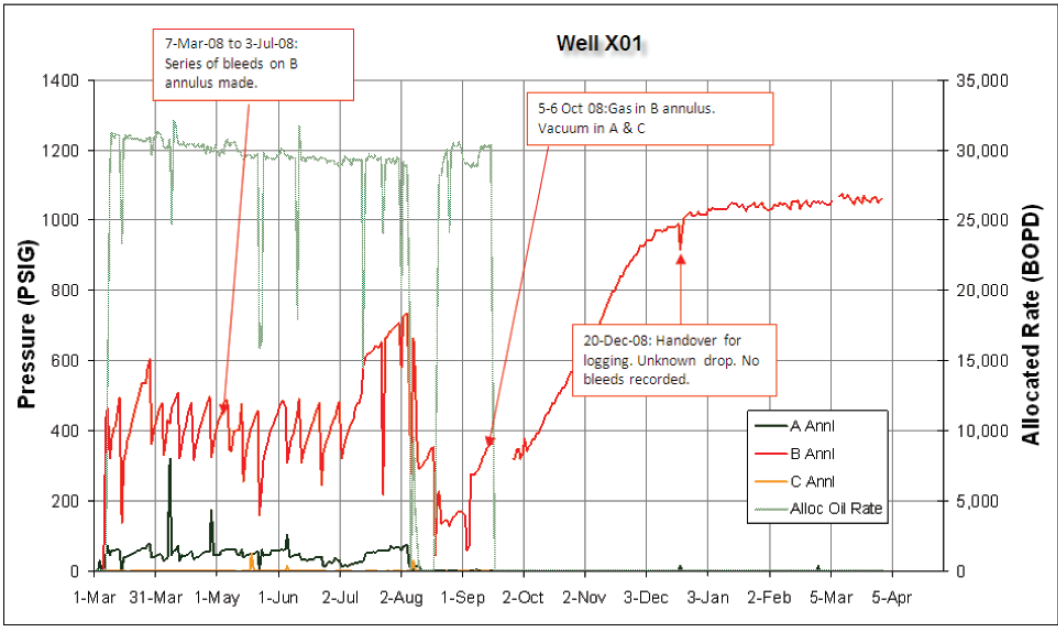
Figure 2.7: Sustained casing pressure on well X01 (Stuart et.al , 2010)

2.6.4 Well integrity at the abandonment stage

The well abandonment phase is often the hardest to manage operationally. Well "ownership" has passed through many different cycles to get to this point. With this maturity a large amount of information has been created. Often the information is not stored in a centralized easily accessible location. There are often data gaps created by poor quality data recording, incompatible software legacy issues, and poor handover during any of the phases, which can have a large impact on risk management in deciding how a well can be abandoned, safely, and environmentally effectively.

Greatest in the uncertainties for well abandonment is often the pressure data. When a production well exhibits sustained casing pressures, diagnosis is difficult and restoration of annulus barriers is difficult. Often sustained casing pressures in production are accepted and managed through a dispensation process. The robustness of the dispensation and risk assessment process, is variable however and some important annulus information such as hydrostatic pressure of annular fluid, and the maximum pore pressure of formation below the shoe, may not be available. It is a fact that those responsible for well integrity management in the production phase have a challenge to persuade management to install an effective well integrity management system and often even to run diagnostic tools. While one can argue that avoidance of production interruptions, limits the use of diagnostics, risk reduction makes their use at all stages essential during the process of abandonment.

3. Existing Alternatives to Cement

This chapter will look at possible alternatives to cement as a sealing material. Nine alternatives are be discussed in this chapter, namely: Thermaset, Sandaband, settled barite, Ultra seal, Fly ash, Ground granulated blast furnace slag, Condensed silica fume, Limestone and CannSeal. Before delving into a discussion into each sealing material, requirements of a material which would qualify it to be a good sealant would be discussed.

3.1 Properties of Materials That Make Them Suitable For Use as a Sealing Material

Materials used for sealing wells must have certain properties to make them desirable for use. The ideal grout should:

- Be of low permeability in order to resist flow through them,
- Be capable of bonding to both the well casing (if necessary) and borehole wall to provide a tight seal,
- Be chemically inert or non-reactive with formation materials or constituents of the groundwater with which the grout may come in contact,
- Be easily mixed,
- Be of a consistency that will allow the grout to be pumped and remain in a pumpable state for an adequate period of time,
- Be capable of placement into the well through a 1-inch diameter pipe,
- Be self-levelling in the well,
- Have minimal penetration into permeable zones,
- Be capable of being easily cleaned from mixing and pumping equipment,
- Be readily available at a reasonable cost, and
- Be safe to handle.

According to Edgley (2002), the requirements imposed on the sealing material are not only the set properties, but the cement slurry properties that allow the material to be placed in the well. He added that considerations during this pumpable fluid stage include the following characteristics, and the key is that these must be alterable to match the requirements of the well.

- **Rheology:** The fluid must be thin enough to be pumpable, but thick enough such that any entrained solids remain in suspension.
- **Pump time:** The length of time the material remains pumpable, so that it can be placed in the annulus properly. Normally, higher downhole temperatures make conventional cementitous materials set quicker than at lower temperatures, aggravating the pump time problem.
- **Transition time**: When cementing across high-pressure gas zones, it is desirable for the transition from slurry to solid occur rapidly, in order to minimize the time between loss of hydrostatic head and the development of strength. During this period of time between the cessation of hydrostatic head transmission and the development of set strength, high-pressure gas can invade the cement column, resulting in loss of sealing integrity.

- **Fluid loss**: This is a measure of a slurried materials ability to retain its liquid phase during the placement process. Excessive fluid loss to the formations through which the slurry is pumped results in dehydration of the slurry and loss of pumpability.
- **Density**: The density of the fluid must be alterable in order to control downhole fluids. If the density is too low, the pressures in the well annulus can fall below the pressure of the fluids contained in the formation, allowing the well to flow prematurely and result in loss of control of the well.
- **Compatibility with other fluids in the wellbore**: Incompatibility may result in lack of attainment of desirable properties, or the inability to properly place the cement.

In addition to the properties required while the material is a liquid or slurry, other properties are required after the material has hardened in the wellbore. As with fluid properties, desirable after the material attains strength must be alterable within certain ranges in order to maximize performance in the well.

- **Compressive strength**: Historically this was the primary aspect of strength that was considered in the design of cement slurries. Recent studies have shown that compressive strength, while important, is only one of several important characteristics of the solid material.
- **Tensile strength**: Increasingly, it is being recognized that cement fails in tension in the wellbore, resulting in cracking and the generation of fluid migration channels. Tensile strength in Portland cement is notoriously low, and the construction industry compensates for lack of tensile strength with steel reinforcing rods or other tension-carrying ductile members. In oil and gas wells, reinforcement options are limited, so the new material must have high levels of tensile strength.
- **Resiliency**: This is a measure of the cement material to absorb stresses without failure. Again, Portland cement is notoriously brittle, so its ability to deform without failure is low. The ideal well cementing material would be sufficiently ductile to deform under load without failing.
- **Shear Bond**: Well cementing materials must bond not only to steel pipe but to a variety of formations encountered in the well. This bonding behavior is the primary mechanism by which the cementing material seals the wellbore fluids in place.

In addition to the above requirements, the chosen sealing material should:
- Not react with contaminants, ground water, or geologic materials.
- Have a hydraulic conductivity comparable to or lower than that of the in-situ material.
- Form a tight bond with the borehole wall and the casing.
- Be resistant to cracking and/or shrinking.
- Be of sufficient structural strength to withstand subsurface pressures.
- Be capable of being placed at the appropriate depth.

No single material will exhibit all of the characteristics mentioned above. Therefore, every situation must be evaluated carefully to determine the appropriate choice. Generally, materials used are comprised of concrete, neat cement, or sodium bentonite.

3.2 Why the need for an alternative to cement as a sealing material?

Cement is a well-known material with properties well documented. However some of these properties are not ideal for handling well integrity challenges related leakage of pressure and

fluids. These are: Shrinking of cement, gas migration during setting, fracturing after setting and long term degradation by exposure to temperature and chemical substances in the well.
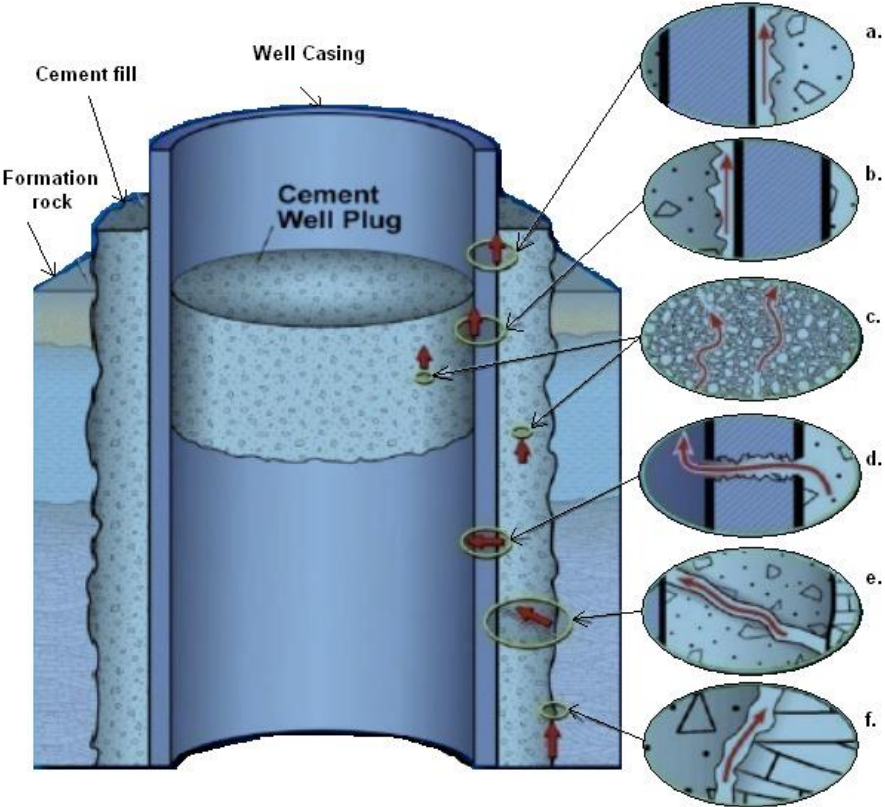
Figure 3.1: Cement problems (Birkeland, 2011)

Figure 3.1 shows several of the problems with cement. a), b) and f) shows leak paths that has occurred due to poor bonding between cement and casing/formation. c) Shows how fluids may migrate due to fracturing of the cement, making it permeable. d) Shows how leakages may occur due to casing failure and e) shows how a flow path may be created in the cement due to gas migration during hardening.

3.3 Description of alternatives to cement as a sealing material

This section would provide a brief overview of the various alternatives to cement as a sealing material.

3.3.1 Settled Barite

During the P & A of wells on the West Ekofisk and Edda platforms, ConocoPhillips used barite that had settled out from drilling fluid as an annular barrier. The idea is that the drilling fluid that is left behind the casing after primary cementing experiences more or less static conditions over a long period of time, causing the barite weight material to settle and form a layer of barite above the casing cement.

When trying to cut and pull a casing during a P & A, problems had occurred with pulling resistance in a section with no cement. It was found that this could be caused by settled barite

from the WBM that had been used during primary cementing. Since the amount of particles in the drilling fluid was known, the assumed height of settled barite could be calculated.

The sealing abilities of the settled barite was verified by setting abridge plug inside the casing, cutting the casing above the plug, and then pressure testing the exposed barite to 70 bar above the fracture gradient of the formation.

It was experienced that a number of conditions has to be satisfied before settled barite could be used as a barrier element.

- During the drilling phase, the well should have been drilled using WBM
- After completion, the well should have experienced closed, static conditions over many years with no history of annulus pressure build up.
- The well should be relatively vertical.

ConocoPhillips are satisfied with using settled barite as a permanent barrier element, and have qualified it for this purpose.

3.3.2 ThermaSet

ThermaSet is a resin-based sealant that sets when it is exposed to a pre-determined temperature for a certain amount of time (Wellcem AS, 2011). In its liquid form, ThermaSet can easily be pumped and injected into small openings such as control lines, because it contains no particles in its neat form. However, particles are normally used to accurately adjust the density from less than 5.8 lbm/gal up to approximately 21 lbm/gal. Other properties, like viscosity and curing time can also be accurately regulated. Compared to cement, ThermaSet has advantages when it comes to mechanical strength. ThermaSet has a higher compressive strength than cement, and also significantly higher tensile strength - approximately 60 times higher than cement. Along with approximately 5 times higher flexural strength, this makes ThermaSet better suited for varying loads than cement. These varying loads could be caused by pressure and temperature cycles that cause the casing to expand and contract, exerting a force on the annulus material.

Testing, Qualification and Certification
31 different qualification tests have been completed on ThermaSet to qualify it as a plugging material (Wellcem AS, 2011). Among those tests, ThermaSet has been tested and qualified according to ISO 14310 V3. This is a liquid penetration test that includes axial loads and temperature cycling. The gas tightness of ThermaSet has been tested satisfactory gas-tight by Proserv in a 5000psi nitrogen test (Wellcem AS, 2001). SINTEF has performed tests to document the mechanical properties, with the results shown in Table 3.1.

Table 3.1: ThermaSet Mechanical Properties Test Results (Wellcem AS, 2001)

Properties	Thermaset	Portland class G" cement
Compressive strength (MPa)	77 ±5	58±4
Flexural strength (MPa)	45 ± 3	10±1
E-Modulus (MPa)	2240±70	3700±600
Rupture Elongation (%)	3.5	0.01
Failure exural strain (%)	1.9±0.2	0.32±0.04

These results show that ThermaSet performs even better than conventional cement in almost every aspect. The Compressive strength and Flexural Strain is exceedingly stronger than that of Portland G cement, the E-modulus show a far superior elasticity, and a highly increased Compressive Strength is demonstrated.
SINTEF also performed an Ageing Test to document long-term integrity of ThermaSet.
The test showed that reservoir conditions have some impact on ThermaSet in a long-term perspective, but the mechanical strength reduction seem to flatten out after a while, and are still satisfactory (over 50% of initial strength). The permeability was also shown to remain low over time. During the Ageing Test, a component in ThermaSet was shown to have issues with H2S, but this component was not needed, and has now been removed from the design (SINTEF 2011)

ThermaSet can be used in many of the same areas as cement, even as primary casing cementing. ThermaSet has about 5 times the bonding strength to steel as class G"cement, and is therefore a strong alternative to cement regarding casing support. It has already been used as casing support in Saudi Arabia, where the mechanical properties was critical for choosing ThermaSet. ThermaSet may also beneficially be used as fill behind casing above the primary cement for zonal isolation and preparation for future abandonment. Either pumped in front of the cement, pumped on the outside of the casing, or squeezed through perforations in the casing. ThermaSet could especially be a very good solution in squeeze plugging, because of its properties as a liquid. The low viscosity and low content of solids makes it easy to pump through small perforations. This advantage could also be used to fix leaking cement plugs with cracks or micro annulus. For deviated/horizontal plugging, ThermaSet also appears as a better solution, because of its uniform resin appearance. Gravity will not affect the placement and quality of ThermaSet the same critical way as for cement.
However, the most important area of use for ThermaSet would be in wells with especially challenging conditions. In wells with high temperature variations, like HPTH-, arctic-, steam injection-, and geothermal wells, ThermaSet seems like the best plugging material, because of its high strength, both compressive-, and tensile strength.

3.3.3 Sandaband

Sandaband is a patented product, developed by Sandaband Well Plugging (SWP), which offers a unique environmentally friendly and operationally efficient plug and abandonment (P&A) method. In 1999, NPD (the Norwegian Petroleum Directorate) encouraged the industry to develop improved P & A techniques due to a growing concern for the number of

abandoned wells on the NCS that were observed to be leaking. Although cement has long been the standard material for permanently plugging wells, it does have a few shortcomings. Compared to the desired properties of a permanent well barrier in NORSOK, cement does not full two properties; it is neither non-shrinking nor ductile. As a result of this, a new ductile plugging material called Sandaband was developed.

Until that time the only material used in this process was cement, but old abandoned wells were already beginning to show signs of unsafe pressure build up. A group of well plugging veterans took up the challenge.

The idea was based on the fact that poorly sorted sand has low permeability, and that a certain particle distribution can form a sand slurry with high solids content that is possible to pump. Hence, a low permeability material could be placed in the well that does not require a chemical reaction to develop hydraulic sealing properties. Sandaband consists of 70% to 80% quartz solids with a grain size diameter varying from less than a micron to a couple of millimeters. The rest of the volume consists of water and chemicals that make the material pumpable. Since quartz and water are chemically stable, these will not degrade over time or react with other fluids except concentrated hydrofluoric acid. On the other hand, the additional chemicals will be exhausted with time, but since these chemicals are only used to make the material pumpable, this does not affect the sealing capabilities of Sandaband. This has been demonstrated by testing Sandaband prepared without chemicals, and the results showed that this mix had the same gas tightness as Sandaband prepared with the chemicals.

As opposed to cement, Sandaband does not set up following a chemical reaction. Instead, Sandaband has the rheology of a Bingham Plastic material. Bingham Plastic fluids are characterized by the fact that they need a certain minimum shear stress to start flowing, but have a linear relationship between shear stress and shear strain. This process is not time-dependant, meaning that the slurry will rapidly form a rigid body when pumping is stopped, without having to wait like cement. Also, if the well experiences dynamic loads that cause stresses in the material, it will simply deform and conform to the surroundings instead of fracturing like a brittle material would.

There are two factors that influence how much pressure a Sandaband plug can control. First of all, the height of the plug gives a hydrostatic contribution with a density of $2.0 - 2.3$g/cc. Secondly; the yield point of the Bingham Plastic material gives a pressure seal that is dependent on the contact are between the plug and the borehole wall. This can be compared to friction in that it works in the opposite direction of the experienced force, preventing the plug from moving until the yield stress is exceeded.

Although NORSOK D-010 does not specify Sandaband or other cement alternatives individually, it does open for using alternative materials as long as these go through a qualification process and an overview of relevant well barrier element acceptance criteria (WBEAC) is made. During the last few years, Sandaband Well Plugging has performed various tests in cooperation with the industry and research institutions in order to qualify Sandaband as a gas tight plugging material. Also, a third-party report was made by Proffshore

to verify that Sandaband fulfils the materials requirements for permanent plugging in NORSOK. This report concluded positively on Sandaband compliance as a permanent WBE, but underlined the need for a sufficient height and length to control required pressure. Since cement can set up to form a solid plug, the hydraulic sealing properties are not as dependant on height and length as Sandaband, meaning that a longer plug may be necessary if Sandaband is used compared to cement.

Another difference between cement and Sandaband is how its placement can be verified. Once a cement plug has hardened, its location can be confirmed by applying weight to the top of the plug, but since Sandaband does not solidify, an alternative method is necessary. The method used is to run pipe slightly into the plug, and circulate bottoms up from below the calculated theoretical top of Sandaband. If sand is observed over the shakers, this indicates that Sandaband is present at the given depth.

However, if the material is placed in the annulus, neither Sandaband nor other materials can be verified using the mentioned techniques. As discussed earlier, cement can be evaluated using cement evaluation tools, and Sandaband in an annulus may also be evaluated using logging tools, although not necessary the same types of tools as for cement. While several tools may be used, the preferred method of logging Sandaband is using a pulsed neutron tool. These contain a high-energy neutron generator that emits neutrons that are bombarded onto the formation. The different nuclei in the formation then interact with the incoming neutrons and start radiating gamma rays. Analysis of the energy spectra can separate between different elements, such as silicon which is abundant in quartz. Since quartz is the main component in Sandaband, its presence can then be identified.

Other methods of verification, like pressure testing and observing operational parameters, are done in much the same way as with cement. As long as the design parameters for the plug are not exceeded, pressure testing and inflow testing can be performed straight after the plug has been placed, since there is no curing time involved.

Tom Friestad, managing director of SWP, discusses the idea behind the Sandaband solution: "Some distinguished veterans from the industry decided to take on the challenge from the PSA. The phenomenon of downhole sand production was well known, as it may cause a prolific high pressure well to become completely plugged, causing costly work-overs to unblock. It was also known that, in order for a sand plug to be gas tight, it needed to have a wide particle size distribution as opposed to a highly permeable gravel pack with very uniform grain sizes. The challenge was then to develop a method for producing a quartz-based, non-consolidating, non-segregating material in industrial quantities at low cost that could be placed in a well using an industry-standard pump. The end result was Sandaband, its name derived from 'SAND for ABANDonment'."

Project manager Vidar Rygg explains its potential applications: "Sandaband was originally developed for permanent P&A but it soon became clear that the fact it does not set up makes it ideal also for temporary abandonment due to its easy removal. Because it does not shrink, fracture, or degrade, it is also excellent for use as an isolation material behind casing.

Something worth mentioning is that Sandaband needs a floor to rest on, so for this behind-casing application it must be used in combination with cement and/or an external casing packer (ECP) to prevent it falling out when the well is drilled further. If Sandaband has not been used preventively behind casing during well construction it can instead be used correctively to remedy sustained casing pressure at a later stage. Finally, it is also a very good lost circulation material (LCM) for curing losses during drilling."

According to Sandaband Well Plugging (2012), Sandaband is an incompressible, everlasting gas-tight material. It is liquid as pumped and solid at rest. Further, it is non-shrinking, non-fracturing, non-segregating, thermodynamically stable, and chemically inert. It is also environmentally safe, has no health hazards, and is non-damaging to the reservoir.

But one of the problems is that the material needs a solid base to be placed on {if it is placed on top of a fluid it will sink. This can be solved with assistance of either a mechanical plug, or another plugging material as a base.

Figure 3.2: Sandaband (Sandaband Well plugging, 2012)

Sandaband consists of up to 85% quartz solids with a grain size diameter varying from less than a micrometre to a couple of millimetres. The rest of the volume consists of water and chemicals controlling the liquid properties like viscosity and freezing temperature.

The quartz particles are kept together by electrostatic forces (Zeta bindings) between the water molecules and the surface of the smallest micro-silica grains, and hinder flow in the pore spaces (Vignes, 2011)

The permeability in Sandaband is dependent on the sorting and packing of the different sized particles (Svinland, 2004). If an optimized mix of different sized particles are carefully mixed and packed in an optimized, tight, dispersed way redistribution or sorting of the particles after placement is minimal, because of the packing and the Zeta-bindings preventing all particle movement relatively to each other. Sandaband has been tested to 5G without segregation. The permeability is also dependent on the saturation and viscosity of the fluid, which can be controlled by chemical additives. The permeability is therefore possible to manipulate and adjust according to desired properties for the particular well conditions.

Sandaband does not set up following a chemical reaction, and therefore requires no setting time, like cement does. Instead, Sandaband has properties like a Bingham Plastic material. Bingham Plastic liquids are characterized by the fact that they need a certain minimum initial shear stress to start owing, but have a linear relationship between shear stress and shear strain, as seen in Figure 3.3
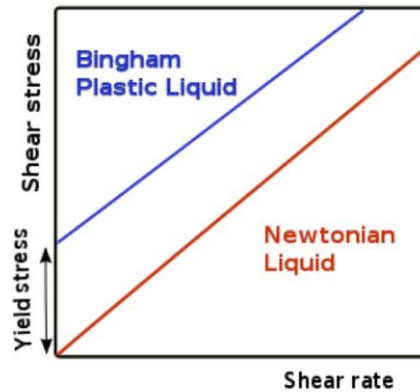

Figure 3.3: Bingham plastic behaviour (Wikipedia, 2012)

This process is not time-dependent; meaning that the slurry will rapidly form a rigid body when pumping is stopped, and can be pumped away like a liquid when re-starting the pumps. Also, if the well experiences dynamic loads that cause stresses in the material, Sandaband will deform and conform to the surroundings instead of cracking and fracturing like a brittle material would. If a cap is needed to ensure the placement and protect Sandaband, it could be used in combination with another plugging material on top. Another advantage of this Bingham plastic material behaviour is that Sandaband has close to zero losses to the formation. When Sandaband enters potential fractures in the formation, it increases its area, and the shear stress needed to move the fluid increase, until Sandaband has filled the fracture openings and sets like a solid again. The low loss to formation makes the needed volume of Sandaband easy to calculate, and it becomes easier to place a successful plug.

There are two factors that influence how much pressure a Sandaband plug can control. First of all, the hydrostatic pressure created by the fluid column, and secondly, the yield point of the Bingham Plastic material, which gives a pressure seal dependent on the contact area between the plug and the borehole wall. This can be compared to a friction force, because it works in the opposite direction of the experienced force, preventing the plug from moving until the yield stress is exceeded. One of the main disadvantages of Sandaband is the fact that it needs to be pre-mixed onshore. This could cause problems regarding uncertainties in volume requirements. The advantage though, is that Sandaband experiences almost zero losses to the formation, caused by its behaviour as a Bingham Plastic material, so volumes should be easier to predict. Another difference from cement is verification of plug placement. Verification of the top of sand slurry is slightly different from verification of top of cement. A cement plug placement and condition would have been verified after curing by tagging with the correct weight, by use of the drill pipe. This is not possible with the concentrated sand slurry because of its behaviour as a Bingham plastic material. Therefore, placing the bottom of the drill string at the planned top of sand slurry and circulating bottoms up, while observing the returns, provides verification of correct placement. If sand is observed over the shakers, this verifies that Sandaband is present at the given depth (Sandaband Well plugging, 2012)

However, if the material is placed in the annulus, neither Sandaband nor other materials can be verified by use of the mentioned techniques. Both Sandaband and cement in the annulus may be evaluated by use of logging tools, although not necessarily the same types of logging tools. While several tools may be used, the preferred method of logging Sandaband is by use of a pulsed neutron tool. These contain a high-energy neutron generator that emits neutrons that are bombarded onto the formation. The different nuclei in the formation then interact with the incoming neutrons and start radiating gamma rays. Analysis of the energy spectra can separate different elements, such as the silicon, which is abundant in quartz. Because quartz is the main component in Sandaband, its presence can then be identified (Sandven, 2010)

Other methods of verification, like pressure testing and observing operational parameters, are done in much the same way as with cement. As long as the design parameters for the plug are not exceeded, pressure testing and inflow testing can be performed straight after the plug has been placed, because there is no setting time involved.

- *Testing, Qualification and Certification*

The gas-tightness of Sandaband has been documented by use of the Intertek JVS 1000 test, which is the recommended test for gas-tight cement slurries on the NCS. Sandaband has also been long-term integrity tested in the temperature range -10°C to 250°C (Vignes, 2011)

Sandaband has also been tested for casing moving and vibration effects on the gas-tightness, with results of no effect on the gas-tightness (Sandaband Well plugging, 2012). This is to prove the capability for the Sandaband to deform and adapt to the changing conditions/loads, proving the properties of a ductile material. There have also been performed self-healing tests, where repeated break-through is forced, and the self-healing capabilities are shown (Sandaband Well plugging, 2012).

Also, a third-party report was made by Proshore to verify that Sandaband fulfills the material requirements for permanent plugging in NORSOK. This report concluded positively on Sandabands compliance as a permanent WBE, but underlined the need for a sufficient height and length to control required pressure. Because cement can set up to form a solid plug, the hydraulic sealing properties are not as dependent on height and length as Sandaband, meaning that a longer plug may be necessary if Sandaband is used compared to cement.

- *Areas of Use*

No required setting time, which saves time, money and eliminates setting time problems, makes Sandaband a good solution in different scenarios. However, the need for a solid base limits this use to reservoir plugging, and plugging in combination with a mechanical plug or another plugging material. Combinations with mechanical plugs may not be optimal, as mechanical plugs are not accepted as permanent barriers, and could fail in a long-term perspective. If a mechanical plug foundation should fail, the Sandaband plug on top may sink and re-position itself, and therefore not provide the same level of safety anymore. In addition, the need for a hydrostatic head does not make Sandaband well suited for use in highly deviated and horizontal wells. Sandaband with its properties for zero losses is a perfect plugging material for zones with challenges regarding heavy losses. This also makes

Sandaband a very good material for fill behind casing to act as a barrier in the annulus. But again, because it is not self-supporting, it needs to be placed on top of a solid foundation.

The ability to be circulated makes Sandaband a perfect material for temporary reservoir plugging. It has an advantage in re-entering the reservoir at a later stage, because the Sandaband plug simply can be washed away and thus no milling or drilling time is needed.

In corrosive environments like CO2 injection wells or wells drilled through salt formations, Sandaband seems like a very good alternative to cement, because it does not react with any chemicals.

3.3.4 Ultra Seal

According to EP magazine wellbore sealant from CSI Technologies is an alternative to Portland cement in a wide variety of wellbore conditions. While the natural density of the epoxy material is slightly greater than water, it can be weighted with no effect on performance. Ultra-Seal R does not readily mix with water, nor is it affected by water contamination. The material set can be controlled from 40°F to 350°F (4°C to 176.6°C). Benefits as a wellbore sealant include improved strength, improved bond strength, non-shrinking and ability to invade permeable solids and harden.

The basic components are a resin and a hardener, although other materials are added to tailor properties and pump time as desired. There are also alternative hardeners available for different temperature ranges. Resin and hardener are mixed on the surface in conventional mixing equipment. Clean-up is with a minimal quantity of a methanol and water mixture. Ultra-Seal R can be batch- or continuously mixed. Ultra-Seal R components are liquid, allowing for more precise mixing than Portland cement.

The material can be weighted to fall though standing water in the well bore or lightened to float on top. Because there are no solids in the basic material, it can be squeezed into casing leaks or into formations. Ultra-Seal R can be used to create virtual well bores in which the resin penetrates into the formation to consolidate weak or damaged zones. When set, the material is impervious to essentially all wellbore fluids and gases. It can be formulated to degrees of hardness ranging from that of hard plastic to stiff rubber. Ultra-Seal is extremely ductile in its set phase; it deforms without fracturing when loads are applied and rebounds to its initial shape when loads are released. Ultra-Seal R is readily drillable and millable using conventional bits.
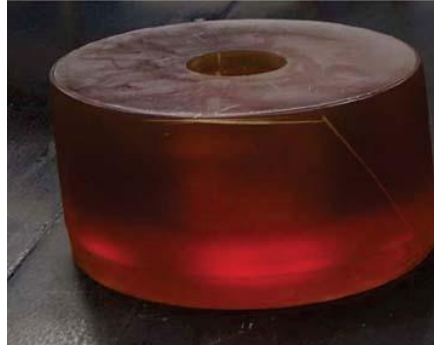
Figure 3.4: Ultra-seal

3.3.5 Use of Alternative Cementitious Materials

Information compiled by Tassel he maintained that Alternative cementitious materials are finely divided materials that replace or supplement the use of Portland cement. Their use reduces the cost and/or improves one or more technical properties of concrete. These materials include fly ash, ground granulated blast furnace slag, condensed silica fume, limestone dust, cement kiln dust, and natural or manufactured pozzolans. The use of these cementitious materials in blended cements offers advantages such as increased cement plant capacity, reduced fuel consumption, lower greenhouse gas emissions, control of alkali-silica reactivity, or improved durability. These advantages vary with the type of alternative cementitious material.

Fly ash is a combustion by-product generated in coal-burning power plants. It is a fine particulate residue removed by a dust collection system. Approximately 40 million tons of fly ash is produced annually in the United States. Fly ash particles are spherical particles ranging from 1-150 mm in diameter. ASTM C618 categorizes fly ash as either Class C or Class F based on the origin of the coal used and the resulting fly ash chemical composition. Class F is a low-calcium fly ash and is pozzolanic, while Class C fly ash exhibits both pozzolanic and cementitious properties because of its high calcium content. The use of fly ash provides improved workability, increased long term compressive strength, reduced heat of hydration, decreased costs and increased resistance to alkali-silica reaction, and sulphate resistance (Class F only) when compared to unblended Portland cement.

Ground granulated blast furnace slag is produced in a blast furnace where iron ore is converted into iron. This slag forms when the silica and alumina compounds of the iron ore combine with the calcium of the fluxing stone (limestone and dolomite). The newly formed slag floats on the liquid iron and is drawn off from a notch at the top of the hearth while the liquid iron flows from a hole at the bottom of the hearth. These reactions take place at temperatures ranging from 1300-1600oC, so the slag is conveyed to a pit where it is cooled. The United States produces approximately 14 million metric tons of blast furnace slag annually (NSA, 1988). The conditions of the cooling process determine the type of blast

furnace slag: air-cooled, foamed, water granulated, or pelletized. Of these types, ground granulated blast furnace slag is both cementitious and pozzolanic. Ground granulated blast furnace slag is a replacement of portland cement and provides several advantages such as improved workability, reduced heat of hydration, decreased costs increased resistance to alkali-silica reaction, and sulphate resistance and increased compressive and flexural strength when compared to unblended Portland cement.

Condensed silica fume is a by-product of the smelting process in the silicon metal and ferrosilicon industry. Silica fume is produced when SiO vapours, produced from the reduction of quartz to silicon, condense. In the United States, approximately 100 thousand tons of silica fume is generated annually (Mehta, 1989). Silica fume particles are spherical with an average diameter of 1-mm and contain approximately 90% silicon dioxide with traces of iron, magnesium, and alkali oxides. When compared to Portland cement, fly ash, or ground granulated blast furnace slag, silica fume is much finer. The addition of small amounts of silica fume (2-5%) increase workability while large amounts of silica fume (>7%) decrease workability, increase compressive strength, decrease permeability and provide resistance to sulphate attack and alkali-silica reaction.

Limestone functions as a supplementary cementing material when it is finely ground with clinker into Portland cement. Limestone quality should have at least 75% calcium carbonate by mass, clay content less than 1.2% by mass, and an organic content less than 0.2% by mass. There are several advantages to using limestone in Portland cement such as reduced energy consumption and reduced CO_2 emissions. Additional cost savings are realized if limestone is available in close proximity to the site. In Portland cements with high C_3A (tricalcium aluminate) contents, the carbonate from the limestone will react with the C_3A during hydration and may increase strength gain and resistance to sulphate attack.

Approximately 14 million tons of **cement kiln** dust are generated yearly in the United States with 9 million tons being reused into clinker manufacturing and 5 million tons discarded (Detwiler et al., 1996). Cement kiln dust varies as the raw material, clinker, and type of operation varies; however, it consists of unreacted raw feed, partially calcined feed and clinker dust, free lime, alkali sulphate salts, and other volatile compounds. After the alkalis are removed, the cement kiln dust can be blended with clinker to produce acceptable cement, and cement kiln dust can be added to Portland cement with other materials such as slag and fly ash.

Other natural pozzolans exist such as volcanic ash, opaline chert and shales, tuffs, and diatomaceous earths. These materials originate from volcanic eruptions and have raw or calcined natural material. These natural pozzolans have large internal surface areas and vary depending on the type of magma from which they originate. Calcined kaolinite is a processed natural pozzolan, which is highly reactive in the presence of lime upon hydration. By including calcined kaolinite in Portland cement, increased compressive strengths and decreased permeability may result (Caldarone and Gruber, 1995).

Alternative cementing materials can directly replace a portion of Portland cement. These materials can be used alone or blended with other alternative cementing materials to produce

cement or concrete with properties different than those resulting from the use of Portland cement. The use of alternative materials affects cement and concrete properties such as workability, hydration, compressive strength, and durability. See figure 3.2 below:
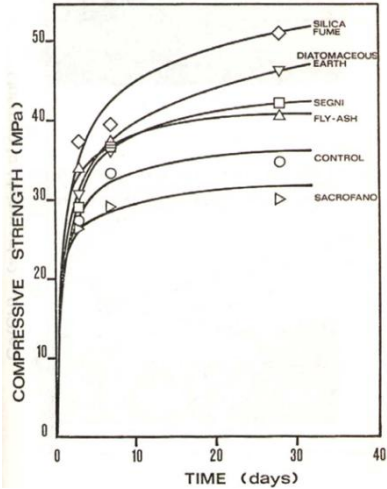

Figure 3.5: Strength development characteristics of different pozzolan-cement mixtures

3.3.6 CannSeal

CannSeal is a new annular zonal isolation technology that has been under development for a few years and is about to be launched. As of May 2012, an application for using the new material is being sent to the Climate and Pollution agency (KLIF) for approval. The material used in the CannSeal technology is an epoxy that can be purpose designed for different operations. The CannSeal service is intended to provide a downhole annular seal. The sealant can be deployed both in an open annulus or gravel/proppant pack.
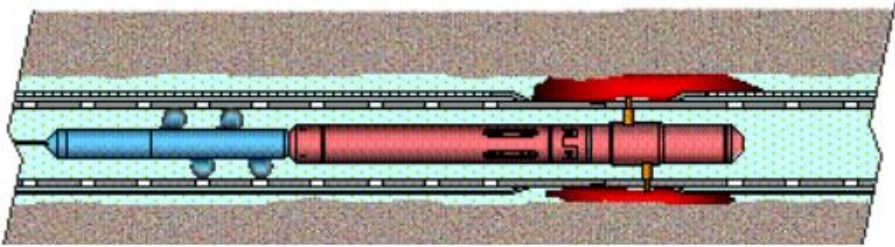
Figure 3.6: The CannSeal technology - Injecting sealant. [www.agr.com/Our-Services/CannSeal/]

The CannSeal system has several applications. Among others are: Sealing unwanted cross flow, sealing water/gas - breakthrough, sealing off leaking packers, sealing off annulus between two pipes, replacing "spot on" cement squeeze, spotting acid and form a basement for plugs sealing both the wellbore and annulus. The latter one is the application most relevant for this thesis. As discussed in the section about Sandaband, the sump effect may be a challenge when setting a plug in an annulus without a foundation. The CannSeal system can be a solution to this problem as described in figure 3.7.

Figure 3.7: CannSeal as foundation for annular Sandaband plug (Nja, 2012)

This methodology can of course also be used as a foundation for permanent annulus P&A plugs in cases where the casing is un-cemented. An idea can be to combine this technology with the Hydrawash technolog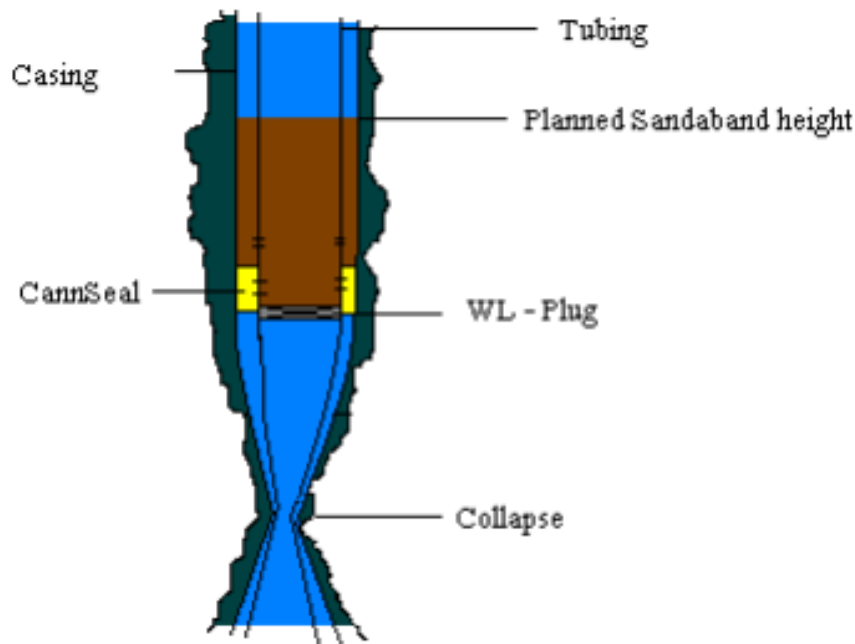y. The CannSeal technology is run on WL and consists of a perforating gun that creates communication with the annulus. When communication is achieved, the injection pads locate the perforations and the tool injects the sealant which is an extremely viscous "dow-like" epoxy that fills the entire circumference of the annulus in about 1 m length as shown in Figure 3.6

3.4 Comparison of New Alternative Plugging Materials

Comparing the new materials with cement, and evaluating the materials based on compliance with the NORSOK requirements, would be done in a tabular form in this section.
The comparison is shown in Table 3.2.

Table 3.2: Comparison of Plugging Materials Compliance with NORSOK Requirements (Skjeldestad, 2012)

Properties for sealing wells	Cement	Sandaband	Thermaset
General Well sealing properties			
Positioning	Verified by logging	Needs solid foundation to be placed on. Verification by circulation or logging.	Can be tagged or logged to verify position
Ability to withstand	OK	Depending on	

Properties for sealing wells	Cement	Sandaband	Thermaset
pressure		hydrostatic head, yield point and contact area.	Stronger than cement.
Withstand environmental conditions	Issues relating to temperature cycling and corrosive environments.	Not affected by temperature cycling and corrosion.	Better suited for temperature cycling than cement.
Desired Material Properties for Permanent Barriers			
Impermeable	Permeability depends on the type of cement and the quality of the cement.	Gas tightness verified through tests, dependent on proper composition and hydrostatic head.	Liquid tightness verified through API V3 test. Gas tightness tested
Long-term integrity	Issues relating to temperature cycling and corrosive environments.	Non-degradable particles.	Tested for long-term integrity
Non-shrinking	Initially shrinking during curing, but additives exists to avoid shrinking.	OK	Initially shrinking, regulated by adding of filler or curing under pressure
Ductile	Brittle.	Able to re-shape and conform to the environments through Bingham plastic behaviour.	Significantly more flexible than cement.
Resistance to chemicals (H2S, CO2, hydro-carbons)	Corrosive. Mechanical degradation in contact with acid gases.	Non-reactive	Component with issues removed from design
Wetting/bonding capabilities	Could have issues regarding mud-removal and poor hole cleaning.	Similar wetting properties as sand. Does not bond to steel. However, gravity keeps it in place.	5 times cement bonding strength to steel. Same issues regarding mud-removal / hole cleaning.

4. Engineering study into selected alternatives to cement

Best practices for evaluating cement plug seal for well integrity behind casing, built on a comprehensive engineering study of the fundamentals governing cement plug seal performance are discussed within this section. This chapter would investigate two selected alternatives to cement in more detail. Both would be x-rayed with a view to isolating the placement and verification of the chosen alternatives. The three alternatives chosen for the study are Thermaset, Sandaband and Laterite loaded mud the later was studied experimentally.

In theory, there are materials with better properties than cement, but no alternative material has yet been used in a primary cementing job. The various environment and different types of well will need different properties and solutions for a primary cementing job, and an alternative material may be used depending on the well.

4.1 Sandaband

Sandaband is the other alternative material which is being assess in a primary cementing operation. While ThermaSet is a particle free resin-based sealant, Sandaband is based on specially sorted sand. Compared to the desired properties of a permanent well barrier element described in NORSOK, Sandaband cement composition do not fulfill two properties; it's neither non-shrinking nor is it ductile. Sandaband has properties that surpass cemen, in this two respects. Listed are the properties that make Sandaband better than cement for primary cementing purposes:

- Incompressible
- Non-shrinking
- Ductile
- Non-fracturing
- None segregating
- Thermodynamically stable
- Chemically inert

Ductility is a mechanical property that describes the extent in which solid materials can be plastically deformed without fracture; therefore, being ductile makes it adaptable to changes in the wellbore, a property ideal for a long lasting primary cementing. The problem with Sandaband is that it lacks the ability to bond to the casing and the formation, and therefore requires a solid fundament to rest on.

Challenges and considerations during a primary cementing when cement is being used will also be important for Sandaband. One of the most important challenges is keeping the casing centralized. It's critical to have the casing centralized when placing Sandaband behind the casing, it has to do with the Bingham Plastic properties and the fact that the flow area is a lot smaller when injecting Sandaband compared to conventional cement placement, because of the solid fundament Sandaband cannot be placed behind the casing conventionally. A

challenge that we can ignore is gas migration, Sandaband does not settle and its gas tight during the pumping stage. Because it's thermodynamically stable, well temperature has no effect on Sandaband.

4.1.1 Sandaband Placement

A solution to place Sandaband as barrier behind casing will involve an external casing packer (ECP) filled with cement; the ECP together with gas tight cement column will work as fundament for the Sandaband to rest on. The plan in the Peon field was to use port collars in order to pump the Sandaband conventional behind the casing after the ECP and the cement column was set. Instead of forcing Sandaband behind the casing by circulating Sandaband conventionally, applying the method of reverse circulation cementing might be a better solution. If RCC where to be used with Sandaband it can reduce the time of the operation because the isolating material is being displaced directly into the annulus. Another positive effect achieved from pumping Sandaband directly into the annulus is a reduction in the equivalent circulation density (ECD); this will reduce the chance of Sandaband invading the formation which can lead to lost circulation. Even though an opening is not required for Sandaband to be injected in, the drilling fluid needs an exit to be circulated back to the surface. Using RCC will still require an opening to be created above the solid fundament where the Sandaband will rest on; this is because the material shall not be placed on top of a fluid column allowing gravitational settling. After Sandaband is successful placed behind the casing, it's necessary to have a detection tool to know when all the mud is displaced out and when Sandaband has been placed properly. This is required to know when to activate the combo tool to close the opening in the port collar.

If we look at the negative side of using the RCC, there is the fluid loss challenge when RCC is being used over intervals of weak formations. Since Sandaband has Bingham Plastic properties. The Bingham Plastic properties will reduce the fluid loss problems because it requires a certain minimum shear stress for the Sandaband to start flowing. Another problem with RCC is that it will require some extra equipment compared to the conventional circulation. Using Sandaband requires many changes to the standard setup, more iron and special kit that is necessary won't make any difference for the operation. If Sandaband where to be used, I would recommend to use the RCC as the placement method for it.

4.1.2 Verification of Sandaband

A good primary cementing job needs to provide adequate zonal isolation in order to prevent cross flow, it also needs to support the casing and protect it from corrosion. With the design purpose stated, it's possible to perform testing on the isolating material. Verification of the Sandaband column is stated in the Well Barrier Element Acceptance Criteria Table (WBEAT) attached in the appendix: The verification requirements for having obtained the minimum Sandaband height shall be described which can be:

Verifications by logs (gravel pack evaluation, bond log), and/or Estimation on the basis of records from the pumping operation (volumes pumped, returns during pumping, etc.).

Usually when a cement evaluation is being conducted, a sonic or ultra-sonic logging tool is being used. When it comes to Sandaband, there may be some other verification methods which can be used. Gravel packing is a process usually undertaken to prevent production of sand and other formation materials to be produced with oil and gas. This is done by placing gravel of a specific size in the annulus. There is a great similarity between gravel packs and Sandaband, where both are composed of unconsolidated rock fragments. Verification of gravel packs may be used for Sandaband. In the WBEAT it is also stated that measurement on the volumes being pumped and the volumes returning can be used to estimated height of the Sandaband column. Logging Sandaband is basically the same as for cement logging; with the difference that Sandaband has less compressive strength than cement. This means that the difference in the measurements above and below Sandaband column will be smaller than a standard cement column. A solution to this is to log 2-3 passes over the interval before and after placement and then compare the data. This may seem troublesome; but it's a method which is often used when dealing with foamed cement. Because the acoustic impedance of foamed cement being similar to the mud/completion fluids, the effect on the logs when using foamed cement is low.

The method mentioned earlier which is being conducted to evaluate gravel packs is the pulsed neutron tool. To describe the method simply, this technique provides a measure of the amount of quartz (behind the casing, the result can be used to determine the top of the Sandaband column because Sandaband consists mainly of quartz. Other methods that can be used is to add a radioactive tracer to the mass, typically a cobalt or iodine isotope with a relatively short half-life (a few days / weeks), then log it with a standard gamma ray tool. It is also possible to log with a density tool. Again, this should be done both before and after placement and then compare values. The methods mentioned, including sonic tools will only give an average of the entire circumference, not all the channels behind the casing will be identified. Over important and critical parts of the well, the best way to evaluate the primary cementing job would be to use ultra-sonic bond log tools. Listed are some Ultrasonic logging tools from various service companies:

Table 4.1: Ultrasonic Tools and the Companies

Ultrasonic Tool	Company
Ultrasonic Imager Tool [USIT]	Schlumberger
Segmented Bond Tool™ [SBT™]	Baker Hughes
Circumferential Acoustic Scanning Tool-Visualization [Cast-V]	Halliburton

4.2 Thermaset

The development of ThermaSet started around 1980 and it has gone through a variety of systematic testing. ThermaSet is initially a product for P&A, repair failed cement and used to fix loss circulation, but it has the potential to be an alternative material for cement in primary cementing because of the improved mechanical properties. Thermaset is originally particle free, and placing of ThermaSet won't be any problem. Information from Wellcem shows that

vital strength of Thermaset is much stronger than of Portland G cement, and Thermaset can withstand stresses caused by casing expansion when the casing it heated by warm reservoir fluids. Thermaset is superior to cement in terms of strength and it can be used in corrosion heavy environments. Just like cement, ThermaSet has challenges and considerations that need to be accounted for. Most of the challenges related to cement will also apply to ThermaSet. ThermaSet is particle free, and to remove the mud in the annulus and the mud cake is important to avoid contamination. Keeping the casing centralized also necessary, because it's easier to displace compared to cement, it's will not be as critical for ThermaSet as it would be when using cement to have a casing centralized. Reservoir temperature will not affect ThermaSet either, the same way as it affect cement. ThermaSet can be designed to settle quite accurately when the temperature is known, according the Wellcem. Casing expansion due to heating can cause tangential tensile stresses in the cement; ThermaSet has proven to withstand tangential tensile stresses.

4.2.1 Thermaset Placement

ThermaSet is originally a particle free substance which can easily be placed. Depending on well structure and down hole environments, the conventional and RCC are both good solutions for ThermaSet. ThermaSet has only been used as remedial cementing and for well integrity solutions, in these cases ThermaSet was placed reversible. If ThermaSet was to be used as a replacement for cement, I would recommend a conventional placement method. Keeping the operation as simple as a possible is the key for using ThermaSet.

4.2.2 Verification of Thermaset

Verification of ThermaSet is normally done by pressure tests except casing cementing. For casing cementing the quality verification is still under developing. Because ThermaSet is particle free, it's hard to say how it's going to response to the acoustic logging tools. Testing and evaluating how ThermaSet will respond to verification methods is critical if Thermaset is to be used as a material for isolation behind the casing. Adding radioactive tracers in the mixture can also be a solution, it's necessary to test if tracers, such as cobalt and iodine isotope have any effect on the properties of ThermaSet. Wellcem could confirm that testing of verification methods were soon to be conducted.

4.3 Applicability of Sandaband and Thermaset

Because of the large variation in challenges, both Sandaband and ThermaSet may be used in some primary cementing operation. In environments with high temperatures and in presence of or other aggressive formation fluids, corrosive attack can be a major problem for the cement sheath. Both Sandaband and ThermaSet are chemically inert and will be resistant to any corrosion attacks, making both potential candidates for future solutions in high corrosion wells. Many wells with corrosion are caused by high temperature, and a high temperature

fluctuation makes the casing expand and contract. The high thermal induced stresses will affect both the casing and the cement sheath,

Sandaband with its ductile properties can be good solutions for temperature fluctuating wells. Test data from Wellcem shows that ThermaSet can withstand large temperature induces stresses. Example of wells with high temperature and large changes in temperature are HDR wells, hydrothermal wells, steam injection wells, arctic wells and HPHT wells.

The well type that might suit the usage of Sandaband best as isolation behind the casing are shallow gas fields, such as the Peon field. The water depth to the sea bed in the Peon field is around 350 meters and the reservoir is 165 meter under the sea bed. The reservoir covers 250 and the gas column thickness ranges from 0-25 meters. This is a very narrow gas column and should normally be developed with horizontal wells. Since the reservoir is just 165 meters beneath sea depth, it's currently not possible to build up a horizontal section. The reason why Sandaband is a good solution in shallow gas fields is because it's a simple well design and due to subsidence and cracking. Subsidence and cracking of the formation will occur when the field has been produced over a certain time; because water from the cap rock is drained into the gas reservoir. Sandaband will serve as barriers element if the cement fails because of subsidence and cracking. Sandaband is a fluid with Bingham plastic properties and can maintain integrity with the cracking and subsidence. Although Peon is a shallow and low pressure gas well, blowout is still a great issue. A vertical well is short and almost frictionless; a blowout can be very costly. Sandaband fills the space between the formation and the casing so that gas cannot flow past and to the surface.

The usage of Sandaband has certain limitation; it's complicated to use Sandaband. By evaluating future usage of the materials for primary cementing, we need to look at what type of wells we might see an increase of. Unconventional oil and gas, thin reservoirs and complex formations are increasing challenges. Long sections of horizontal wells, branched completions and side tracking are well designs to overcome in the future. Solutions involving Sandaband in these types of well designs is not an option, the usage of Sandaband is already complicated without the extra challenges.

While well design such as long sections horizontal section with narrow spacing, side tracing and other complicated well scenarios is not suited for Sandaband. Using ThermaSet can be a much easier in a complicated well design, if ThermaSet is able to support the casing. The test results from Wellcem confirm that the Young's Modulus of ThermaSet is lower than classical Type G cement. It's uncertain how long sections of casing ThermaSet can support, in cases where ThermaSet can't support the casing; cement needs to be used together with ThermaSet. The solution of combining cement and ThermaSet will be too time consuming and too expensive.

Oil well cementing cost can be broken down into 3 major categories;

- Cost of rig time
- Cost of services
- Cost of material

Table 4.2 shows a relative cost comparison between the alternative materials with conventional cement.

Table 4.2: Cost Comparison between the Alternative Material and Conventional Cement (Nja, 2012)

Primary Cementing Material	Rig Time	Cost of Services	Cost of Material
Conventional	High	Low	Low
Sandaband	Low	High	Medium
ThermaSet	Medium	Medium	High

The price of conventional cement without special cements additives is low. The cost of services is also low and we can use the conventional rig time as a standard to compare with the two other materials.

The cost of Sandaband is more expensive compared to conventional cement, when it comes to more sophisticated cement mixture it is probably more similar, or perhaps even lower. A cost increase will come from the extra services needed to deal with a more complicated operation. A reduction in rig time will account for the extra cost from material and extra services. Even though the usage of Sandaband will require a fundament of cement, the rest of the material does not need time to settle.

This is the factor where time and money can be saved in the operation. Depending on the well, a reduction of 10-20 hours can be achieved if executed properly. Using a material that does not settle has other positive side with it also. Reduced risk of pumping is not straight forward to quantify, cementing into a drill string is one of the critical risk when dealing with cement, days and up to weeks of rig time can be lost, reduced risk of wrong cement settling or wrong cement placement is clearly an advantage of using a non-hardening material.

If conventional cementing procedure were to be used for ThermaSet, a reduction in rig time can be achieved. Even though ThermaSet will require time to settle, the settling time is very low compared to cement. The cost of services will be increased due to dealing with an unconventional material; I assume that there will be some extra services when using ThermaSet. The main problem with ThermaSet is the cost of the material. ThermaSet is at least 5 times more expensive than cement, and it's not clear if is this is conventional cement or special cement. Even though material cost is a small part of the cost of a well construction, it can be determine factor for a material trying to compete with the cheaper conventional cement. The last factors which can be discussed are cost savings related to a reduced number remedial cementing job. Because cement has some issues when it comes to long lasting zonal isolation, both the alternative material has better properties for a longer lasting primary cementing, which will reduce the number of intervention needed. This cost saving regarding to a reduced number of remedial operations are very hard to quantify, the number of remedial cementing operation needed is impossible to predict, the cost and the time used to fix a well vary a lot, and the cost of shutting a well down for maintenance depends on the value of a well.

4.4 Barite Loaded Mud

The aim of the experimental work reported here was to study the behaviour of barite loaded mud as an alternative to cement as a sealing material. The following properties were to be tested and compared with Portland cement: gas tightness of the mud, its compressive strength and how it must be handled to create longer plugs.

4.4.1   Experimental conditions studied

Composition of seal

The seal is composed of water, bentonite and barite. This composition as depicted in Table 4.3 was chosen because the properties of barite and bentonite when mixed were used as a drilling fluid which serves the function of forming a mud cake on the borehole wall, thus serving as a temporary seal which holds the formation in place before cement is used as a permanent seal for holding the casing in place.

Table 4.3: Mixture composition

Material	Mixture 1	Mixture 2	Mixture 3
Bentonite (g)	80	120	140
Barite (g)	350	400	400
Water (litres)	2	3	5
Water/material ratio	2:5	4:3	2:7

Barite Loaded Mud Rheology

The experimental findings reported here were obtained with water and several grams of barite and bentonite were mixed for every one 1.5 litres of water giving different plastic viscosities and increased stepwise to obtain higher viscosities. These concentrations were used to provide comparable effective viscosity to that which would be anticipated in a hole section using a field mud.

The values for the three mixtures are shown in Table 4.4 and is plotted in figure 4.1

Table 4.4: Table Showing Mixture Rheologies

	RPM	600	300	200	100	6	3
DIAL READINGS	MIXTURE 1	38	33	28	23	14	13
	MIXTURE 2	122	103	87	66	59	47
	MIXTURE 3	350	310	275	136	90	79
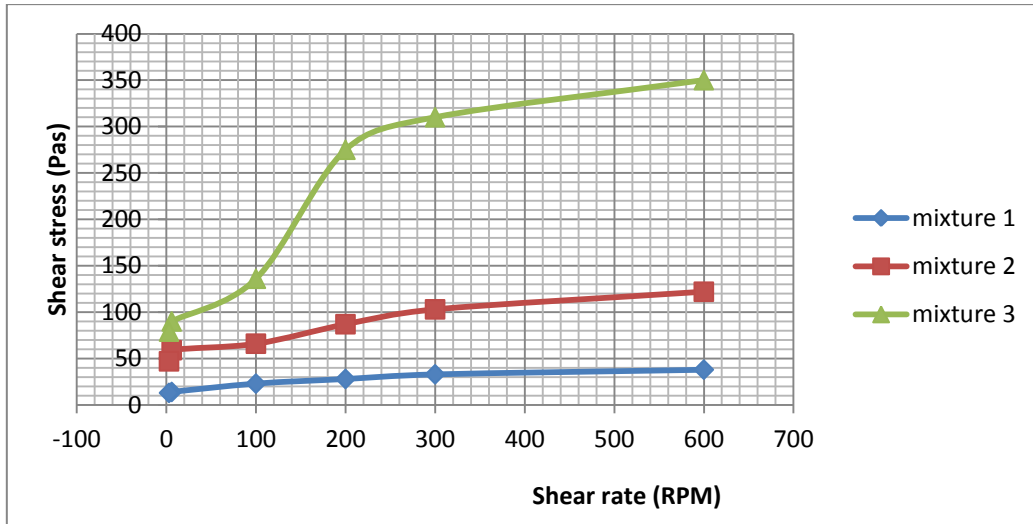
Figure 4.1: mixture rheologies

Table 4.5: Table Showing Mixture Properties

Mixture	1	2	3
Density (kg/m^3)	1.18	1.24	1.28
Filterloss (ml/30mins)	13	10.6	8.2
Gel strength	18	23	17

Table 4.6: shear strength measurement

	Mixture 1	Mixture 2	Mixture 3
Shear strength(bar)	0.13	0.2	0.23

4.4.2 Test facility and test matrix

The test facility is as shown as in Figure 4.2. This facility was constructed in a way that the test plug could be fitted into a steel pipe with the other connections such as the pressure guage for pressure reading, the hydraulic pump etc. as shown
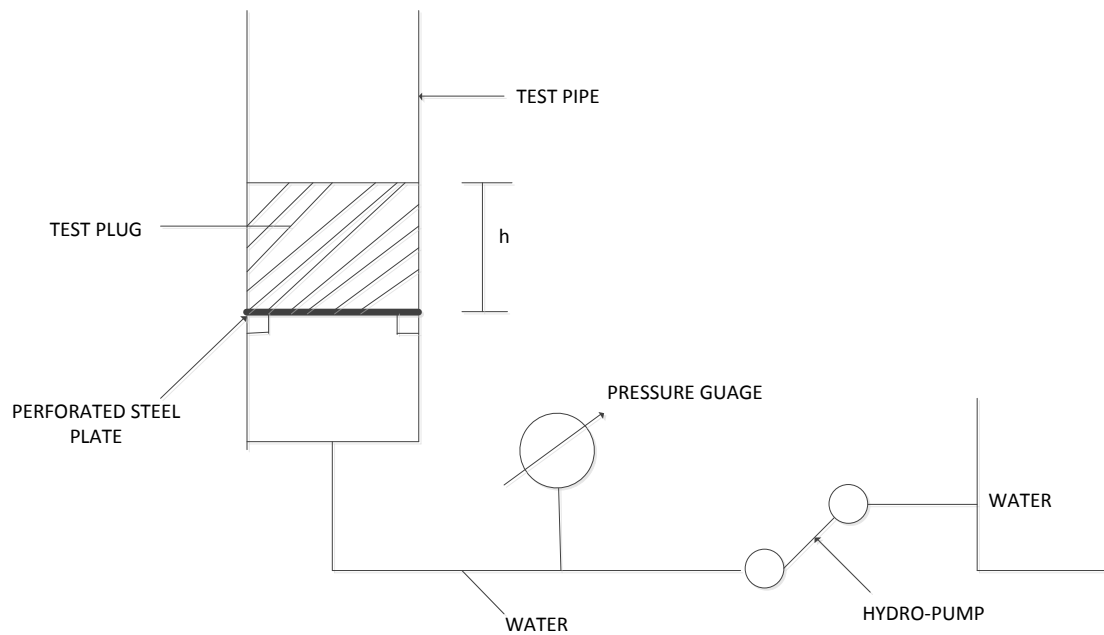
Figure 4.2 Schematic of test facility

Test matrix

In the test matrix we have 3 test sets, every test set will contain 5 test elements that will be carried out at the same experimental conditions. A total of 15 different tests were performed using slurries of barite loaded mud.

Table 4.7: Sealing materials used in comparison

Description	A	B	C
Bentonite-Barite Ratio	**50-50**	**60-40**	**70-30**
Density (kg/l)	1.18	1.24	1.28
Setting time (hrs)	1.4	1.5	1.7
Fluid loss (ml/30 mins)	13	10.6	8.2
Gel strength	18	23	17

4.4.3 Test procedure
- The test facility is shown in Figure 4.2
- 140ml of each of the mixtures was poured into the plate. Waited for 1 day to allow the mixture to set. I connected the pump to the bottom of the pipe and applied pressure in the following way:
- started with pressure of 0.0 bars

- Continued increasing the pressure in small quantities until the maximum pressure where the plug moves.
- Recorded this pressure. This procedure is summarized in Figure 4.3
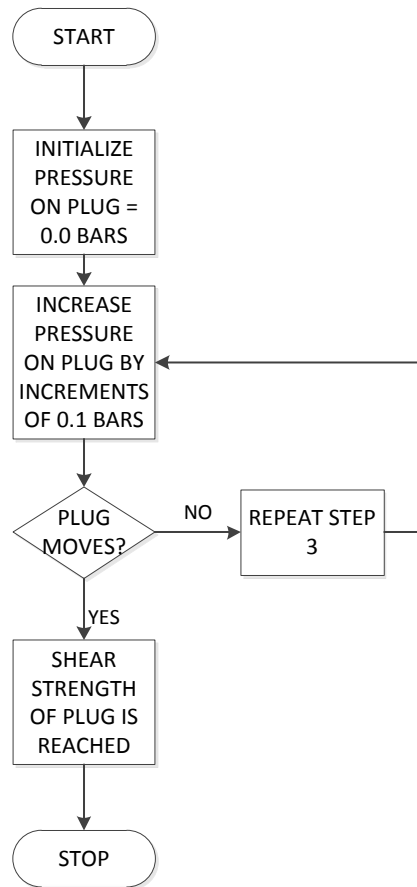

Figure 4.3: Flow chart for determining shear strength of barite plugs

4.4.4 Results

(a) Shear Strength Test

The shear strength test on the barite loaded mud was performed in accordance with the procedure spelt out in the section 4.4.3. Figure 4.4 shows the results of the testing the muds. The published shear strength of Portland cement was used in comparison with the other three mixtures of bentonite and barite mud. The idea was to compare which of the mixtures competes favourably with the shear strength of cement. From the results we see that mixture #3 having a bentonite- barite ratio of 70:30 had higher shear strength than the other mixtures.
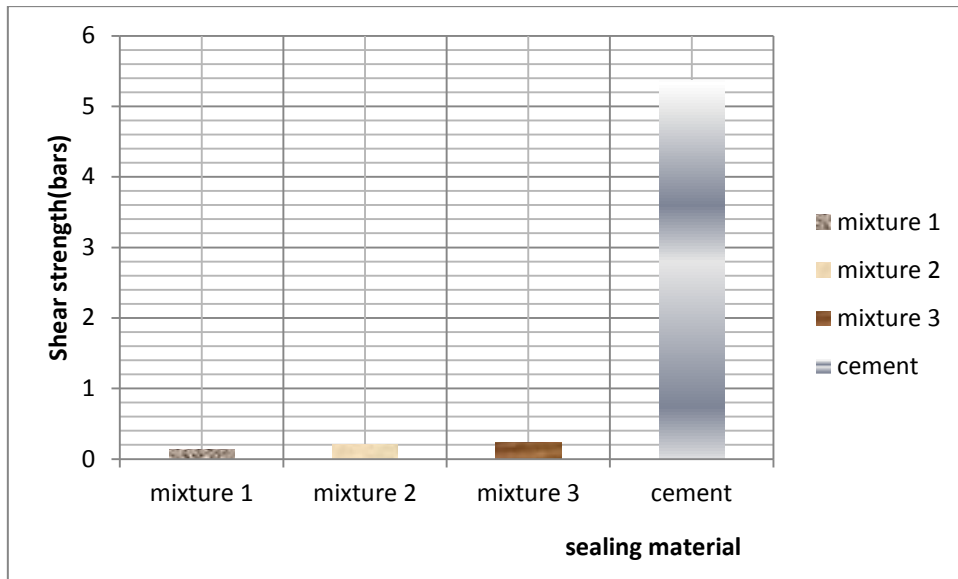
Figure 4.4: Shear strength of three sealing materials compared with Portland cement Mixture

(b) Filter Loss Test

The filter loss test on the barite loaded mud was performed in accordance with the procedure spelled out in the section 4.2.1. Figure 4.5 shows the results of the test. The published filter loss value of Portland cement was used in comparison with the other three mixtures of bentonite and barite mud. The idea is to compare which of the mixtures has lower filter loss value compared with the filter loss of cement. From the results we see that mixture three having a bentonite- barite ratio of 70:30 had higher shear strength than other mixtures.
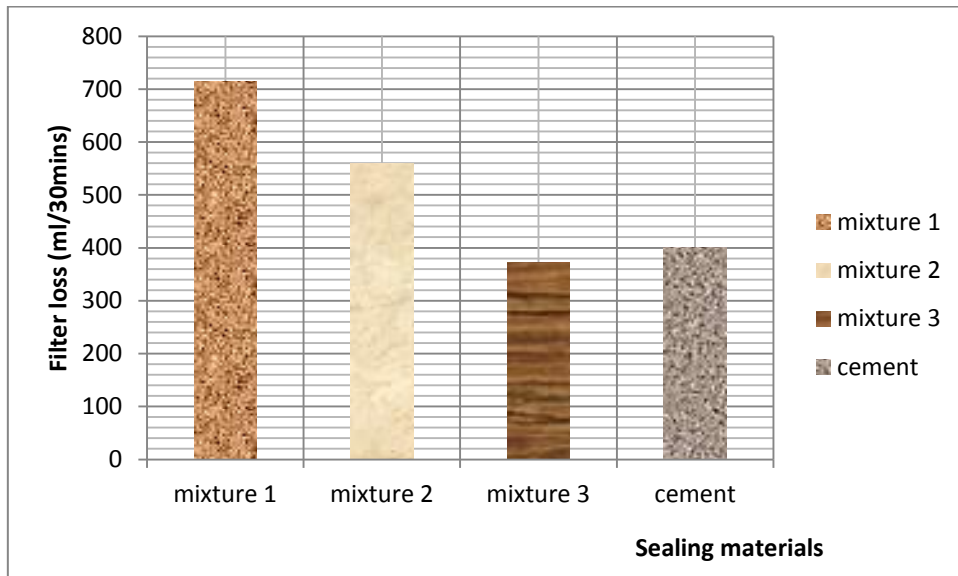

Figure 4.5: Filter loss of three sealing materials compared with Portland cement mixture

(c) Gel Strength Test

Gel strength is the shear stress measured at low shear rate after a mud has set quiescently for a period of time (10 seconds and 10 minutes in the standard API procedure, although measurements after 30 minutes or 16 hours may also be made) (Schlumberger, 2012)

The Gel strength test on the barite loaded mud was performed in accordance with the procedure spelt out in the preceding section. Figure 4.6 shows the results of the test. The published gel strength of Portland cement was used in comparison with the other three mixtures of bentonite and barite mud. The idea is to compare which of the mixtures competes favourably with the gel strength of cement. From the results we see that mixture three having a bentonite- barite ratio of 70:30 had higher gel strength than other mixtures.
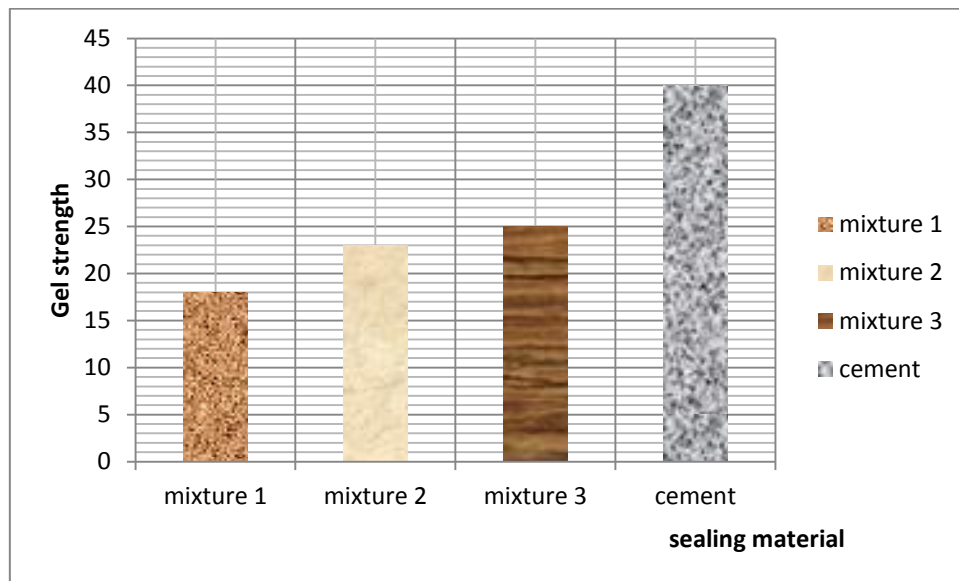

Figure 4.6: Gel strength of three sealing materials compared with Portland cement mixture

(d) Setting Time Test

The initial setting time is the interval between the mixing of the mud with water and the time when the mix has lost plasticity, stiffening to a certain degree. It marks roughly the end of the period when the wet mix can be molded into shape. The final setting time is the point at which the set mud has acquired a sufficient firmness to resist a certain defined pressure.

The setting time test was performed to find out which of the mixtures has a quicker setting time compared to that of Portland cement. It was done in accordance with the procedure spelt out in the preceding section. Figure 4.7 shows the results of the test. The published setting time of Portland cement was used in comparison with the other three mixtures of

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bentonite and barite mud. The idea is to compare which of the mixtures competes favourably with the average setting time of cement. From the results we see that mixture three having a bentonite- barite ratio of 70:30 had a quicker time of set than other mixtures.
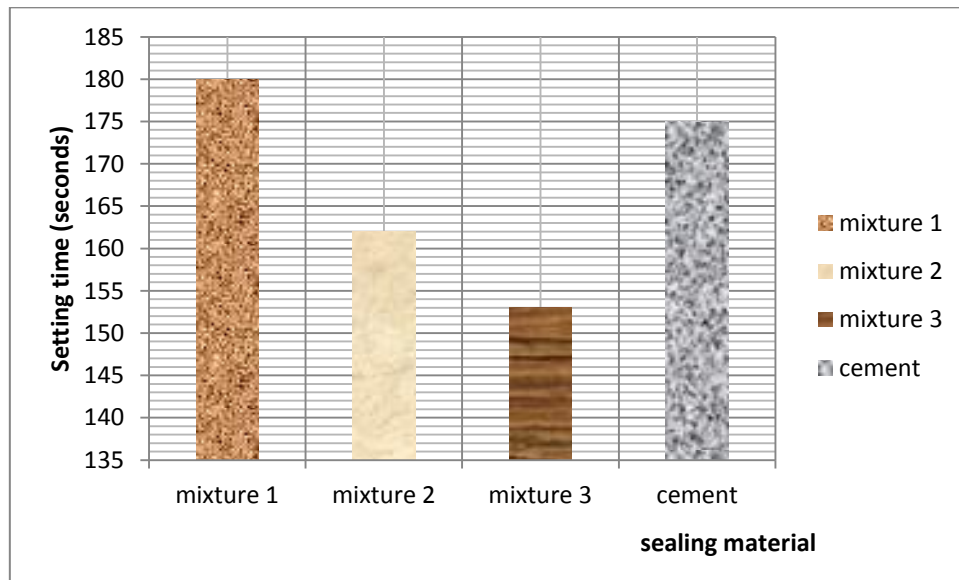

Figure 4.7: Setting time of three sealing materials compared with a typical standard Cement slurry

5. Discussion

As the situation is today, ThermaSet and Sandaband cannot compete with standard cement slurries used in a primary cementing operation. Cement will still be the first and only choice for a primary cementing material for now. Currently, Sandaband and ThermaSet are still at a testing stage and both alternatives seem to have limitations.

In order to make Sandaband more competitive as a primary cementing material, it needs to be qualified as a primary cementing material. Experience needs to be gained in order to develop method and improve equipment to best suit Sandaband. Data to prove that Sandaband is a trustworthy option for cement is needed. If we look at the properties of Sandaband, the properties are ideal for long lasting isolation purposes.

The properties that make Sandaband better than cement for primary cementing purposes are:

- Incompressible
- Non-shrinking
- Ductile
- Non-fracturing
- None segregating
- Thermodynamically stable

How did swellable elastomer packers manage to replace cement in completion jobs while the usage of Sandaband in primary cementing has not been tested? One of the reasons for using the SEP was because cement could not be used in those applications. An argument to use Sandaband instead of cement is based on the long term limitations of cement.

Another reason why SEP managed to enter the market is because the SEP is easy to deploy. It will automatically swell once placed downhole, the procedure of placing Sandaband is even more complex than cement. The usage of horizontal wells is becoming a standard in the oil and gas industry, and the primary cementing challenges are becoming harder to overcome. Listed are the challenges that make it hard to get a good cement job in horizontal wells.

- Hole cleaning and drilling-fluid displacement
- Centralization of pipe
- Optimizing cement slurry designs
- Evaluation with acoustic tools

In cases where the challenge is too great, using cement may not be an option, and it will be impossible to use Sandaband. If we look at the possibility to sidetrack a well at a later stage, using Sandaband can be a problem. Sandaband does not act like cement, it is ductile and movable. When sidetracking through the Sandaband, the material will start to circulate out from where it was placed originally and back to the surface. To stop this, a window is needed

to be drilled through the Sandaband and a cement pillar needs to be placed to create isolation and a new fundament for the Sandaband to rest on.

This needs to be done in order to drill further on. Not only is it a very complex procedure, but it can be an issue for the well integrity.

Other application which were it may be too complicated to use Sandaband is in the Arctic. Although, Sandaband is good in temperature fluctuating environments, in the Arctic, all operations get more difficult. A complicated operation such as Sandaband is not recommended. Most of the steam injection wells are horizontal or the most complex SAGD wells are multilateral, the usage of Sandaband in these wells is also limited. Currently, the only type of well where it can be utilized and benefit from Sandaband today is shallow gas wells.

ThermaSet bonds to steel very well and has a higher mechanical strength than any well cement. The people from Wellcem also claims it resist temperature up to 320 degree Celsius. If we compare ThermaSet with Sandaband, ThermaSet does not have the issue of a complicated placement method. The largest issues with ThermaSet are the cost and uncertainty of supporting the casing. ThermaSet will bond to steel, but there are not data available showing the capability to support the casing. The other issue is related to verification, no test has yet been conducted to see how well ThermaSet will respond to the sonic and ultra-sonic logging.

Currently the best way to improve primary cementing is not to replace cement with other materials, but specially design a cementing program best suited for the well operation. Table 6 is a cement system overview created to show the diversity of cement in this discussion.
Regarding to the lack of ductility which has been identified as a major reason for cement failure; flexible and expandable cement systems was developed to prevent cement sheath cracking. The use of vulcanized rubber a very good solution, but is also very costly. The diversity of the cement systems gives another alternative for ductile cement; foamed cement. Foamed cement exhibit improved ductility over conventional cement, at least a magnitude more ductile than conventional cement.

Foamed cement is often chosen for primary cementing because it shows great displacement properties and it has a low density, which makes it great for problem such as depleted zones, high pressure zones and formations with a narrow pressure, it's also useful when there are concerns over reservoir compaction or salt-formation flow.
If there were a cheaper solution for ductile cement, why did they have to develop flexible and expandable cement systems?

This has to do with the limitations of foam cement; Listed are some limitations with foamed cement:
- Fracture and pore pressure profile
- Permeability of formation
- Density of the lead slurry

- Safety factors
- The length of a foam column

Because foamed cement slurry is permeable, there must me a limitation on the permeability. And the limitation is often less than one-tenth of the formations permeability. Although the density of foamed cement should be low, it has to be able to contain the pore pressure of the formation; this creates a lower limit on the density. When designing the foamed cement, it also important to remember that a purpose of primary cementing is to support the casing. Depending on the regulations, the compressive strength of the cement should be in excess of

100 psi, even above 500 if it's required by regulations.

If we take a short comparison between these two ductile solutions of cement systems; even though foamed cement is more expensive than conventional cement it is cheaper than flexible cement, but flexible cement is one of the most durable cement that can be used.
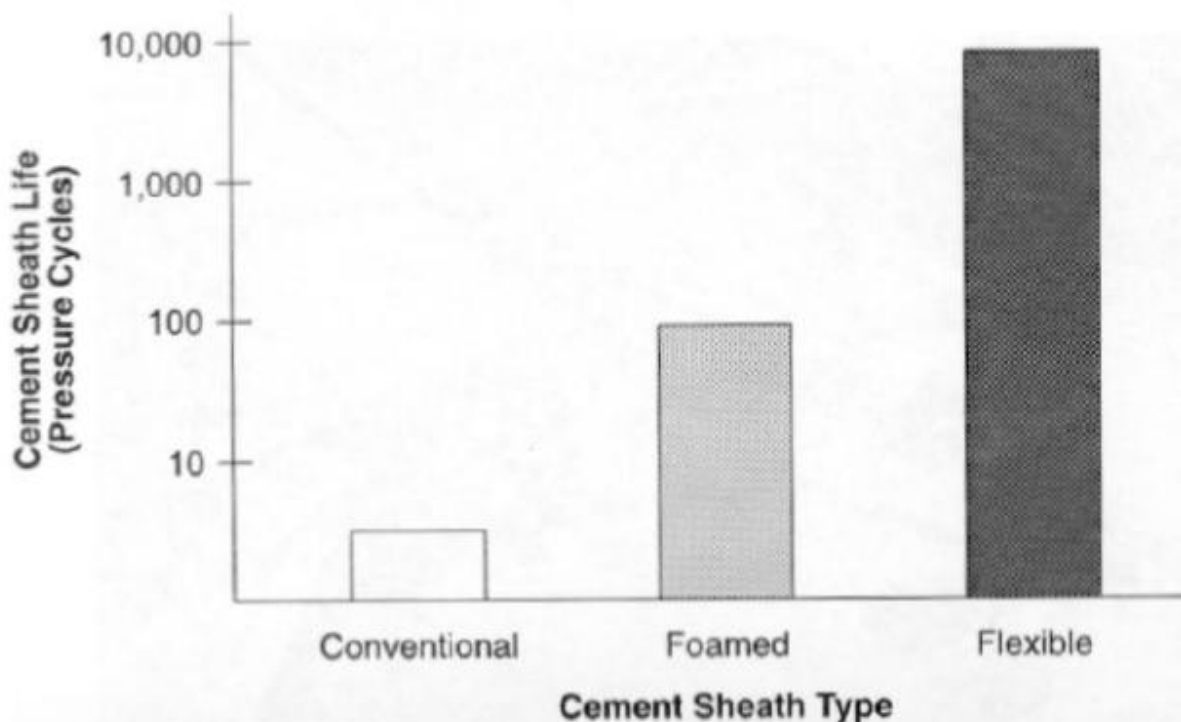

Figure 5.1: This Figure Shows The Number Of Pressure Cycles The Given Cement Can Endure, A Way To Classify The Durability Of The Cement (Kopp et.al., 2000)

The flexible cement is not as ductile and as long lasting as Sandaband, but it has a longer life than foamed cement and it can offer a longer well life in sour(/sweet(well applications. In search for a long lasting primary cementing, flexible cement can be a decent solution. But the cost of flexible cement is high, and I don't think it will be used as a standard well solution.

Another way to improve primary cementing with regards to the materials, combining cement can be solution, especially if they have properties that work well together. An example that might work is combining HGS and foamed cement.

Foam cement is somewhat opposite from the HGS in regards of price, since nitrogen is cheaper than the base slurry it will become cheaper as more nitrogen is added to the mix. However, as more foam is increased the compressive strength is decreases and permeability, compressibility and elasticity will increase. A decrease of compressive strength and increase of permeability is not beneficial for primary cementing, but an increase of compressibility and elasticity is often helpful. Compressibility will help counter losses in hydrostatic pressure and a higher elasticity helps maintaining a long term seal.

In order to face the challenges in the large variation of primary cementing operations, these two lightweight solutions are not good enough by themselves. By combining them together, it's possible to create solutions to new challenges. High strength low permeability slurries can be designed by using high quality hollow glass spheres and then using foam to achieve the required density. A mixture between these two low density solutions can result in high strength slurry with low perm, good elastic and compressible strength.

Designing a cement program by combining different cement systems and use SEP to support and protect the cement sheath is the best way to achieve a long lasting primary cementing.

6. Conclusion

Failure to deliver and maintain well integrity can have significant damaging effects on production, costs, reputation and credibility. Well integrity is a critical subset of production assurance and is therefore a core driver for business success. The industry as a whole has not established clear and unambiguous definitions for well integrity, and the range of interpretation as to what constitutes effective well integrity management is huge. It is therefore difficult for regulators to mandate well integrity conformance when the industry cannot offer a common definition and framework. The consequences of poor well integrity management can, in some cases be immeasurable. However, for the most part, good well integrity practices will maximize the life of the well, its productivity, and most importantly its safety while minimizing well maintenance costs.

By carefully examining the data and visual reports offered by downhole instruments, well integrity engineers are able to assess potential problems. Whenwells at risk areas are discovered, protocols can be initiated to circumvent disaster or delay its onset until proper repairs can be made. When all of these elements work together, the safety and integrity of the oil well can be effectively maintained.

In order to improve the well integrity through primary cementing operation, alternative materials to replace cement have been evaluated. The alternative materials- Sandaband and ThermaSet has been evaluated. A conclusion that can be drawn from the evaluation is:

- Cement will still be the only material for primary cementing in the near future. This is because of the superior ability to support the casing, the diversity of cement, low cost and due to the state of the industry.

- The property of the alternative materials makes them possible candidates for future corrosion heavy and temperature fluctuating wells. Sandaband can also be used as isolation behind the casing in shallow gas wells. The usage of Sandaband will be limited to simple well solution because of the complex of the operation. ThermaSet is currently too expensive, and there are too many untested issues related to it as a primary cementing material.

- Instead of replacing the materials, challenges and considerations related to the usage of cement needs to be dealt with. A better primary cementing design involving different cementing systems and preventive measures such a swellable packers can strengthen the cement and making it more viable for long lasting zonal isolation.

To attain effective zonal isolation and hence optimum well performance, the selection of a well sealant should be engineered. The compressive strength of a sealant, which is traditionally used as a quality indicator, is not sufficient to decide which sealant is most suitable for the effective zonal isolation of the well. Other mechanical properties such as its Young's modulus, Poisson's ratio, Tensile Strength, Shear Strength and Bonding Strength are also required.

Organizational solutions are also required to ensure the required well integrity is maintained. This will include, amongst other things, that the operating company ensures that people with the right competence are working with well operations and that they are up to date with the latest well status. Good communication between the parties involved is required so that the correct information is shared and passed on at e.g. shift handovers. In handover documentation, all relevant information with regards to barriers, operational limits, valve status, design of the well etc. has to be compiled as part of a handover package. Many problems and accidents have been due to poor handover documentation or communication, and good routines and organizational solutions for this is required to maintain the required l Good operational solutions are also required to ensure that the well integrity requirements are met. A typical example is the requirement to regularly function and pressure test the sub-surface safety valve to ensure it is operational at all times. The operational solution will include procedures for operating valves on a well, flowing restrictions etc. that can have an impact on the integrity of the well and other day-to-day activities to keep a well under control and producing it in a safe manner. Another example is to continuously monitor the pressure in the annuli of a well to ensure a leak or breach of a well barrier is detected early and that corrective action can be taken before the problem escalates.

7. Nomenclature

ASR	=	Alkali –Silica Reaction
ASTM	=	American Society for Testing and Materials
BI	=	Bond Index
C_3A	=	Tricalcium Aluminate
CBL	=	Cement Bond Log
CET	=	Cement Evaluation Tools
CO_2	=	Carbon (IV) Oxide
DST	=	Drill stem test
GPa	=	10^9 Pascal
MPa	=	10^6 Pascal
NCA	=	Norse cutting and Abandonment
NCS	=	Norwegian continental shelf
NCS	=	Norwegian Continental Shelf
NORSOK	=	The competitive standing of the Norwegian offshore sector (Norwegian)
NPD	=	Norwegian Petroleum Directorate
OLF	=	Norwegian Oil Industry Association (Norwegian)
OREDA	=	Offshore reliability data
P&A	=	Plug and Abandonment
PDS	=	Reliability of computer-based safety systems (Norwegian)
PET	=	Pulse Echo Tool
P_f	=	Fracture pressure
PFD	=	Probability of failure on demand
PMV	=	Production master valve
P_o	=	Pore pressure
PSA	=	Petroleum Safety Authority
PWV	=	Production wing valve
QRA	=	Quantitative risk assessment
RBD	=	Reliability block diagram
RIDDOR	=	Reporting of injuries, diseases and dangerous occurrences regulations
ROV	=	Remotely operated vessel
RSC	=	Risk status code
S.G.	=	Specific Gravity
SCASSV	=	Surface controlled annular safety valve
SCM	=	Supplementary Cementitious Materials
SCP	=	Sustained casing pressure
SCSSV	=	Surface controlled subsurface safety valve
SIL	=	Safety integrity level
SINTEF	=	Foundation of Science and Technology at the Norwegian Institute of Technology
SIS	=	Safety instrumented system
TLP	=	Tension leg platform
TR-SCSSV	=	Tubing retrievable surface controlled subsurface safety valve
UK	=	United Kingdom
UKCS	=	UK continental shelf
US GoM	=	US Gulf of Mexico
WBE	=	Well barrier element
WBEAC	=	Well Barrier Element Acceptance Criteria

WBM	=	Water Based Mud
WRF	=	Well risk factor
WR-SCSSV	=	Wireline retrievable surface controlled subsurface safety valve

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9. Appendix

This Appendix shows the Well barrier elements acceptance tables according to NORSOK.

General technical and operational requirements and guidelines relating to WBEs are collated in table A.1. The methodology for defining the requirement/guidelines for WBEs is:

Table A.1: Requirements for Well barrier elements

Features	Acceptance criteria	References
A. Description	This describes the WBE in words.	
B. Function	This describes the main function of the WBE.	
C. Design (capacity, rating, and function), construction and selection	For WBEs that are constructed in the field (i.e. drilling fluid, cement), this should describe • design criteria, such as maximal load conditions that the WBE shall withstand and other functional requirements for the period that the WBE will be used, • construction requirements for how to actually construct the WBE or its sub-components, and will in most cases only consist of references to normative standards. For WBEs that are already manufactured, the focus should be on selection parameters for choosing the right equipment and how this is assembled in the field.	Name of specific references
D. Initial test and verification	This describes the methods for verifying that the WBE is ready for use after installation in/on the well and before it can be put into use or is accepted as part of well barrier system.	
E. Use	This describes proper use of the WBE in order for it to maintain its function and prevent damage to it during execution of activities and operations.	
F. Monitoring (Regular surveillance, testing and verification)	This describes the methods for verifying that the WBE continues to be intact and fulfils it design/selection criteria during use.	
G. Failure modes	This describes conditions that will impair (weaken or damage) the function of the WBE, which may lead to implementing corrective action or stopping the activity/operation.	