The People's Democratic Republic of Algeria

Ministry of Higher Education and Scientific Research

Serial N°:………./2022

Kasdi Merbah University – Ouargla

Faculty of Hydrocarbons, Renewable Energies and Earth Sciences and the Universe

Drilling and MCP department

THESIS

In partial fulfillment of the

requirements for MASTER'S

DEGREE

Major Subject: Professional Drilling

Realized by:

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Title of Master's Thesis:

Well Integrity Management: Annulus Pressure, Causes and Solutions

Submitted on: June 8th, 2022

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2021-2022

Dedication:

Our deepest gratitude goes to all of our family members our parents, brothers, sisters. It would not be possible to write this thesis without their support.

We would sincerely like to thank all our beloved ones who support us through thick and thin.

May Allah shower the above cited personalities with success and honor in their life.

Acknowledgement:

In the name of Allah, the Most Gracious and the Most Merciful.

All praises to Allah and His blessing for the completion of this thesis. We thank Allah for all the opportunities, trials and strength that have been showered on us to finish writing this thesis. We experienced so much during this process, not only from the academic aspect but also from the aspect of personality. Our humblest gratitude to the holy Prophet Muhammad (Peace be upon him) whose way of life has been a continuous guidance for us.

We would like to sincerely thank our supervisor. Dr. Mouley Ibrahim Khalil for his guidance, understanding, patience and most importantly, he has provided positive encouragement and a warm spirit to finish this thesis. It has been a great pleasure and honor to have him as our supervisor.

May Allah shower him with success and honor in his life.

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Abbreviations & nomenclature:

API: American petroleum institute

BOP: Blowout preventer

CBL: Cement bond log

CSD: Casing setting depth

CSS: Casing shoe strength

DHSV: Downhole Safety Valve

ECD: Equivalent circulating density

FIT: The formation integrity test

HPH: High-Pressure and High-Temperature

HSE: Health, Safety and the Environment

HSR: High Sulphate Resistant

IOCs: International Oil Companies

KPI: Key Performance Indicator

LOT: Leak-off test

LTC: Long thread connection

MAWOP: Maximum annular working pressure

MSR: Moderate Sulphate Resistant

NCS: Norwegian Continental Shelf

NOCs: National Oil Companies

NOGEPA: Netherlands Oil and Gas Exploration and Production Association

NORSOK: Norwegian Petroleum Standardization Organization

OBM: Oil-based mud

OWC: Oil well cement

P&A: Plugging and abandonment

PSA: Petroleum Safety Authority

ROP: Rate of penetration

RPM : Revolution per minute

SAP: Sustained casing pressure

SCP: Sustained casing pressure

SCSSV: Surface controlled subsurface safety valve

TOC: top of cement

VDL: Variable density log

WBE: Well Barrier Elements

WIF: Well integrity forum

WIM: Well Integrity Management

WIMS: Well Integrity Management Software

XLOT: Extended leak off test

General introduction:

Events around the world are accelerating; the world economy is directly tied to its latest developments. The petroleum (oil and natural gas) industry in general seemed flexible as it was affected by these events. As oil and gas prices fluctuate and decline around the world, also the need of moving to the unconventional challenging fields, a number of factors must be reviewed in order to boost the profits and protect the sustainability of the industry. Based on a new developed technology procedures, methods and solutions in helping reduce the upstream (exploration and production, E&P) oilfield operation costs. Global oil leaders, organizations, IOCs & NOCs (International and National Oil Companies) are seeking to explore ways to develop oil industry technologies since these latest events (1).

Well integrity undeniably is considered one of the most important topics of the petroleum industry. Failure in not keeping a well integrity system functioning adequately may result in disastrous accidents called blowouts with all tragic consequences that they may bring: human lives loss, loss of drilling equipment or production facilities, loss of hydrocarbon reserves and pollution, Also, well integrity issues may lead to substantial financial losses during the entire well life cycle as a result of non-productive operational time and/or remedial solution. The situation is aggravated when considering deepwater scenarios.

Unfortunately, in 2010 the oil industry faced its worse accident caused by the loss of well integrity: blowout of Macondo in the Gulf of Mexico with devastating consequences to the oil industry. The accident has been demanding from all players (operators, drilling contractors, service companies, regulators, industry organization, academia and training providers) a huge amount of effort to minimize the risk of having this kind of accident repeated. Originally, those efforts were aimed at Deepwater drilling activities in the Gulf of Mexico but with time they were disseminated throughout the oil industry activities all over the world (1).

Significant progress has been made to enhance the safety during all phases of the well life cycle since the Macondo blowout happened (2).

This thesis intends to present and discuss well integrity fundamentals, identify different causes leading to well integrity failure, procedures taken to maintain well integrity during a well life cycle, and how to manage well integrity.

So, what is well integrity? Why well integrity is important? What can go wrong in wells? What are the consequences of loss of well integrity?

Loss of well integrity accidents may happen; after investigations are made the major important priority is the prevention and risk minimization of having this type of accidents repeated. By making a huge amount of effort to develop technologies, equipment, researches, personal training, and set recommendations.

So, what are the results from our case study investigations?

Our thesis is divided into six parts. The first part is a general introduction and the last one is conclusion. The four other parts are subdivided into four chapters as follow:

In the first chapter, well integrity definition, different phases in well life cycle, general principals of well barrier, types of failure and well integrity issues, risks assessment and management system.

The second chapter is about integrity of cement and casing includes casing and cement fundamentals, procedures of well head installation and different annulus pressure.

The third chapter explains how to evaluate cement bond, defining cement bond log and its working method, interpreting the results and checking cement quality.

By the end of this thesis, the fourth chapter is focusing on cause analysis, consequences resulting from “well A” accident.

CHAPTER ONE

WELL INTEGRITY GENERALITY

I. 1. Introduction:

Well integrity refers to the comprehensive application of technical, operational and organizational management solutions to reduce the uncontrolled leakage risk of formation fluids throughout the entire life cycle of the well, by ensuring that the safety risk level of oil and gas well construction and operation is controlled within a reasonable and acceptable range, the goals of reducing oil and gas well accidents and economically and safely operating the oil and gas well are achieved.

The consequences of well integrity problems can include equipment failures, casualties loss of production and environmental pollution, leading to enormous economic losses, severe corporate reputational damage, and even company closures. In recent years, with more and more high-temperature wells, high-pressure wells, high-productivity wells and deep wells have been explored and developed, well integrity challenges continue to increase. Once the integrity problems occur, the consequences for oil companies will become increasingly serious. Especially after the Deepwater Horizon accident in the Gulf of Mexico in 2010, well integrity caused widespread concern worldwide.

So what is well integrity?

Well integrity can be defined as well's capacity to maintain zonal isolation of geologic formations and prevent fluids migration (native or injected) between these formations. To ensure this isolation, the well casing and the host rock are bonded by a cement sheath; after abandonment, a cement plug is used to avoid upward migration within the casing. The safety and performance of most subsurface operations are dependent on well integrity, including that of active wells used for the operations or of existing wells abandoned after prior operations. Detailed reviews or best practices on well integrity have already been performed.

I. 2. Definition of well integrity:

Well integrity is in general terms related to the functionality of a well to prevent loss of containment or its ability to perform its intended functions. However, there are various definitions that differ in both scope and focus area, that are briefly outlined in this section.

The NORSOK D-010 standard governs well integrity on the Norwegian Continental Shelf (NCS), and is here defined as "application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of

A well, the standard focuses on establishing well barriers by use of Well Barrier Elements (WBE), their acceptance criteria, their use and monitoring of integrity during their life cycle. The risk element is the uncontrolled release of formation fluids, while the integrity aspect covers technical, operational and organizational solutions that will either lower the probability of the risk occurring, or reduce the consequences, should it occur.

Another common standard from the oil & gas industry is the API RP 17N. In this standard, integrity is defined as the ability of a system of components to perform its required function while preventing or mitigating incidents that could pose a significant threat to life, health and the environment over its operating life. This is a broader definition, as the risk aspect is not limited to loss of containment, but rather any potentially harmful event, while there are also no specific dimensions (such as technical or organizational) to the integrity aspect. The term integrity management is also included and is defined as "the systematic implementation of the activities necessary to ensure that critical systems are properly designed and installed in accordance with specifications, and remain fit for purpose until they are retired" (2).

NOGEPA Industry Standard no. 90 is a Dutch oil and gas standard that defines asset integrity. The definition of well integrity is expressed as "the ability of the well(s) to perform its required function effectively and efficiently whilst protecting Health, Safety and the Environment (HSE)".Well Integrity Management (WIM) is the means to ensure that the people, systems, processes and resources which deliver integrity are in place, in use and will perform when required over the whole lifecycle of the well(s). The definition is similar in scope and focus to API 17 RP 17 N.

ISO/TS 16530-2:2014 is a standard explicitly addressing well integrity, covering the operational phase of oil & gas wells. Here, well integrity is defined as “containment and the prevention of the escape of fluids (i.e. liquids or gases) to subterranean formations and surface”, while well integrity management is “a combination of technical, operational and organizational processes to ensure a well’s integrity during the operating life cycle”. Similarly to NORSOK D-010, the risk element is limited to the escape of formation fluids, while the integrity aspect covers processes aimed to prevent loss of containment.

There are no similar standards that explicitly define well integrity for geothermal wells, but there are standards that cover design and best practices, that also cover well integrity. One of the most common reference documents in the geothermal industry, is the New Zealand NZS 2403:2015 Code of practice for deep geothermal well drilling, used by the geothermal industry and regulators worldwide. This document covers all life-cycle phases of the well, and provides guidance on managing the well site, drilling equipment, tools and materials, drilling techniques and well integrity management (3).

I. 3. Development History of Well Integrity:

In 1977, the Bravo blowout of Phillips Petroleum Company, Norway first proposed the concept of well integrity. In the following nearly 40 years, well integrity technology has been developed and widely used in Norway, the United Kingdom, and the United States.

In 1996, the Norwegian Petroleum Safety Authority (PSA) began to systematically conduct well integrity technology research and promote its application in Norwegian offshore oil and gas fields.

In 2001, in response to the well integrity challenges caused by annulus pressure in the oil and gas wells in the Gulf of Mexico, Louisiana State University, Schlumberger, Stress Engineering Services, etc. carried out continuous research and published “Continuous Casing Pressure Diagnosis in Wells and final reports on remediation and remedial measures Comments on the phenomenon of continuous casing pressure on the outer edge of the continental shelf. Best practices for the prevention and control of continuous casing pressure and other research reports, systematic analysis the annular pressure conditions of oil and gas wells in the outer continental shelf area of the United States were analyzed. Based on the statistical analysis of a large number of field data, researches on diagnostic analysis, preventive measures, and remedial measures of annular pressure were carried out (4).

In 2004, following the blowout accident at the Norwegian National Petroleum Corporation's Snorre A platform, the Norwegian Petroleum Standardization Organization NORSOK D-010 "Guidelines for Well Integrity during Drilling and Operations" released the third edition, which proposed the concept of well barrier management. The system describes the measures to ensure the integrity of the wellbore in the process of ensuring safe production. Various oil companies and operators have begun to pay attention to and use this standard.

In 2006, API first published the recommended practice RP 90 "Recommended Practice for Annular Pressure Management in Offshore Oilfields" designed to guide the management of annulus pressure in offshore oil and gas wells; this recommendation covers the monitoring of annulus pressure and the diagnosis of annulus pressure testing, establishment of single well maximum annular working pressure (MAWOP), and recording of annular pressure. This recommended practice has become an important guidance method for managing annulus pressure in offshore oil and gas wells abroad.

In 2007, Norway released the Well Integrity Management Software (WIMS) for the first time and established the WIF Well Integrity Association. Many companies have developed their own well integrity management systems. A large number of oil companies have adopted well integrity management systems to improve well integrity technology and management level. Oil and gas well integrity management system is a continuous management, evaluation and verification system used to ensure the continuity and reliability of well design, construction, monitoring and maintenance throughout the life cycle.

In 2009, the American Petroleum Institute released the "API HF1 Wellbore Structure and Well Integrity Guidelines" for the protection of groundwater and the environment in response to the integrity of hydraulic fracturing wells (5).

In 2010, after BP's Macondo blowout in the Gulf of Mexico, well integrity caused widespread concern and rapid development worldwide:

In 2012, the British Petroleum Association released the "Oil & Gas UK Well Integrity Guide", which aims to guide well barrier design, installation and testing at all stages of the well's life cycle;

In 2013, the ISO organization released "ISO/TS 16530-2 Production Well Integrity", which aims to guide the monitoring, testing and management of production well integrity. In the same year, the Norwegian Petroleum Standardization Organization absorbed the industry's complaints about the accident. Based on the 450 recommendations, the fourth edition of NORSOK D-010 was revised and published.

In 2015, the American Petroleum Institute (API) released the API 100-1 "Fracturing-Well Integrity and Fracture Control"; 2016 Life Cycle Well Integrity Guide Third Edition, API releases RP90-2 onshore annulus pressure management, OLF releases Well Integrity Recommended Guide revision; 2017 ISO release 16530-1 full life cycle well Integrity management.

In recent years, well integrity monitoring, evaluation, and technology have developed rapidly abroad.

While a large number of well integrity technology research and standard preparation work have been carried out, developed countries have successively formulated and improved a large number of well integrity related laws and regulations to ensure the effective implementation of well integrity work. Norway's petroleum industry management regulations, petroleum equipment design and configuration regulations all require well barrier design and monitoring requirements; UK offshore installation safety case regulations, well design and construction regulations, and other requirements related to well integrity; EU offshore safety regulations recently issued requirements for independent well integrity reviews (6).

I. 4. Well life cycle:

All wells follow a similar life cycle, regardless of their purpose, with some variations in their design and operational aspects. The well life cycle, as outlined in ISO 16530-1 Petroleum and natural gas industries has the following phases (7):

- Basis of design phase,
- Design phase,
- Construction phase,
- Operational phase,
- Intervention phase,
- Abandonment phase.

I.4.1. Basis of design phase:

The basis of well design phase is where the objectives of the well are set and the full life cycle operational requirements are determined, to allow for detailed design of the well in the next phase. Some of the information that is required at this phase includes (7):

- The location,
- Targets – formations and depths,
- Well type (that is, exploration, production or monitoring),
- Well subsurface architecture (vertical, deviated or horizontal),
- Geological information, including expected formations, aquifers, faulting and temperatures,
- Geomechanical information, including pore pressures, rock strength, in situ stresses, porosity, permeability and temperatures,
- For an exploration well, data acquisition requirements,
- For a production well, production parameters such as production rates, the composition of the fluids and gasses that will be produced, and the stimulation and testing strategies that will be used,
- Potential for planned re-completion or conversion of the well for other purposes (converting an exploration well to a monitor well, for example),
- The expected operating life of the well.

The geology of the resource and the overlying strata that must be drilled through to reach it are important because they determine the depth, thickness and gas content of the target shale horizon. Although shale resources are typically made up of flat lying layers of rock, geological features such as folds and faults are important in determining the geometry of the resource. Igneous intrusions may also cut through the resource, and the design of the well trajectory will need to take these features into account.

Geomechanical properties are important because they describe how rock will respond mechanically (deform or break) as it is drilled through. An open well will fail if the stress concentrations around its circumference exceed the strength of the rock. Geomechanical parameters such as in situ stress, rock strength and pore pressures are important for the design of the casing in the well. These parameters are also important for hydraulic fracture design (8).

Overpressures in formation fluids are an important consideration for well design and well integrity. If the pore pressure is at the hydrostatic gradient, there is no driving force for fluids to move vertically between layers of rock at different depths, or to the surface. If the pore pressures are above the hydrostatic gradient, they are said to be over pressured and those pressures can drive the flow of fluids vertically between formations to the surface, should a pathway be available. A well with good integrity will be able to control these overpressures.

Overpressures develop naturally as a result of a range of mechanisms through geological time, and low to moderate overpressures are present in many shale resources. Gas and oil can move vertically owing to their buoyancy and expansion, even without overpressure, but water cannot move vertically without a driving force.

These geological, geomechanical and operational considerations are all important for well integrity. These factors need to be taken into account so that the design of the well reduces risks to its integrity (9).

I.4.2. Design phase:

In this phase, all aspects of the well are designed in detail, taking into account the overall life cycle of the well and all future operations, through to its eventual abandonment. The design is based on a detailed analysis of data and requirements collected during the previous phase, and include the following aspects (10):

- Well design, and specification of materials and equipment (such as casing, cement and completion),
- Data acquisition program, including well logging, sample collection and well testing,
- Well stimulation activities, if required,
- Barriers to managing well integrity,
- Operating procedures, including risk management and well integrity management,
- Plans for final abandonment of the well.

The design of the casing, cementing and completion are important for long-term well integrity. Casing is steel piping that provides a pressure tight conduit between the shale gas resource and the surface.

Wellbore casing is a highly engineered product that is designed to cope with anticipated wellbore conditions. International standards cover the manufacture, testing, engineering specification, mechanical properties and performance of the casing. The casing prevents the unintended flow of drilling and hydraulic fracturing fluids out of the well, keeps the well open through weak or broken rock layers, and prevents formation fluids from entering the well and from moving between layers of rock via the well (11).

I.4.3. Construction phase:

The well construction phase involves drilling and completion of the well in accordance with the design. A focus during this phase is managing the risks associated with drilling and maintaining well integrity. Well control refers to the prevention of ‘kicks’, which are uncontrolled flows of formation fluids or gases into the wellbore that can reach the surface. A severe kick can lead to a blowout, which is the uncontrolled escape of fluid from the well.

Drilling fluids are an essential component of drilling operations, and are distinct from the hydraulic fracturing fluids used during well stimulation. These fluids provide cooling and lubrication to the drill bit and drill string, lift drill cuttings from the well and are a component of well control. The density of the drilling fluid is increased by the use of additives to counteract any overpressures in the formation, preventing kicks and helping to maintain wellbore stability in uncased sections of the well. If the density of the drilling fluid is too high, drilling fluid may be lost in layers of rock. Additives that create a low-permeability skin on the wellbore can be used to limit these losses (10).

Casing is installed and cemented in place in a number of stages during the construction phase. Initially, a large-diameter surface casing is set sufficiently deep to protect surface aquifers, and is fully cemented in the ground. Once a well is drilled to either the design depth or a depth where a casing string is required, a steel casing string is run into the borehole and cemented. The cement fills and seals the annulus between the casing strings, or between the casing string and the formation rock. This process is repeated until well construction is complete (9).

In each stage, the well is prepared (essentially, cleaned by the circulation of drilling fluid) and cement is then pumped down the center of the well so that it flows around and up the annulus between the casing and the surrounding rock. The well integrity provided by the cement depends on both the cement slurry design and several other aspects of the well cementing process; for example, preparation of the wellbore, and the condition and centralization of the casing. Ideally, the wellbore and casing would be prepared for cementing as follows (9):

- The wellbore diameter should be close to the drill bit size (known as the gauge),
- The surface of the wellbore should be smooth,
- During drilling, breakouts or washouts of the surrounding rock should have been minimized by good design of the drilling mud,
- There should be no formation fluid influx into the wellbore or major loss of drilling mud to the surrounding rock,
- The casing should be centralized, with a sufficiently wide annulus surrounding the casing to allow cement flow,
- The drilling mud in the hole should be properly conditioned to remove pieces of rock that may slough off the walls of the well.

During the construction phase, components of the well that contribute to the well's integrity are tested to verify that they are performing as designed. Verification is an important element of well integrity management. The integrity of well casing and cement can be tested by pressurizing the well, to verify that it can hold the pressures that it may be exposed to over its life. A variety of downhole logging tools can be used to measure the state of the casing and the integrity of the bond between the casing, cement and rock (10).

For production wells or wells used for formation testing, hydraulic fracturing (also known as well stimulation) activities are undertaken as part of the construction phase.

The final activity in the construction phase is the 'completion' of the well, preparing it for the production of gas .Completion involves the installation of hardware in the well to allow the safe and efficient production of gas from the well at a controlled rate, and many different completion technologies are available. If the well was drilled for other purposes, or if the well is to be suspended, the completion will be designed accordingly. For example, instruments such as pressure meters or temperature sensors may be installed in a monitoring well during the construction phase (10).

I.4.4. Operational phase:

For production wells, the operational phase will have the longest duration, with some wells producing hydrocarbons for decades. During this phase, the main activities are monitoring the well's integrity and performance, and maintenance. Abnormal pressures in the annulus between casing strings can indicate integrity issues, as can changes in production rates. Wireline logging, in which measurement tools are lowered down the well on a wireline, is generally the only means of checking the integrity of casing and cement down the well.

Observations from a sample of wells can be used to indicate the integrity of wells across a field (9).

I.4.5. Intervention phase:

In some cases a well must be re-entered to perform maintenance, repairs or replacement of components; for surveillance; or to increase productivity. Such interventions are also referred to as 'workover'. Interventions can be critical to maintaining well integrity, and a range of technologies are available for repairing casing and cement. Production wells may be hydraulically re-fractured to extend their production, and the design of such activities needs to be commensurate with the design of the well and its current condition, allowing for any corrosion or other deterioration (12).

I.4.6. Abandonment phase:

The abandonment phase is the final phase in the well life cycle; in this phase, the wells are decommissioned, plugged and abandoned. The goal of plugging and abandoning the well is to ensure the integrity of the well in perpetuity, effectively re-establishing the natural barriers formed by the impermeable rock layers that were drilled through to reach the resource. Once a well has been abandoned, there is little prospect of re-entering the well for any purpose. Monitoring may be conducted after the well has been abandoned, to confirm that plugs have been properly set in the well. The well's ongoing integrity should not be dependent on long-term monitoring [although such monitoring may be conducted to confirm the effectiveness of abandonment practices. The aims of abandonment are to (10):

- Prevent release of formation fluids or well fluids to the environment (including aquifers),

- Prevent the flow of groundwater or hydrocarbons between different layers of rock,
- Isolate any hazardous materials left in the well. The method of plugging and abandoning a well involves confirming the well's integrity to ensure that there will be no movement of fluid into or out of the well, and placing barriers in the well to prevent the vertical movement of fluids between rock layers. A schematic of an abandoned well. The plugs typically comprise cement with mechanical plugs or retainers. To provide long-term integrity, the cement (or other barrier material) must (13):

  - Not shrink,
  - Be able to withstand the stresses in the wellbore,
  - Be impermeable,
  - Be impervious to chemical attack from formation fluids and gases,
  - Be able to bond with steel casing and rock,
  - Not cause damage to the casing. The design of well abandonment must be considered during the design phase of the well. For example, the casing material that will be left in the well must be compatible with the objectives of abandonment.

I.5. General Principles of Well Barriers:

The principle of well integrity is primarily occurred with maintaining well control with sufficient barriers. Well integrity is defined as "application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the lifecycle of a well". To control the well, two qualified independent well barrier envelopes should be present at each stage of a well's life. The petroleum industry has employed the principle of a two-barrier philosophy since 1920s. Generally speaking, the overbalance from the drilling fluid is the primary barrier and the blowout preventer (BOP) with casing string comprise the secondary barrier during well construction. Over time, the petroleum industry has entered into more complexed and challenging environments, and therefore, the need to clarify and standardize the well barrier integrity has been increasing. In practice, the application of the well barrier philosophy is more complicate due to technical and operational limitations. Figure I.1 illustrates the two-barrier philosophy of a well throughout its lifecycle, and Table I.1 presents examples of barrier systems through its lifecycle of the given well (14).

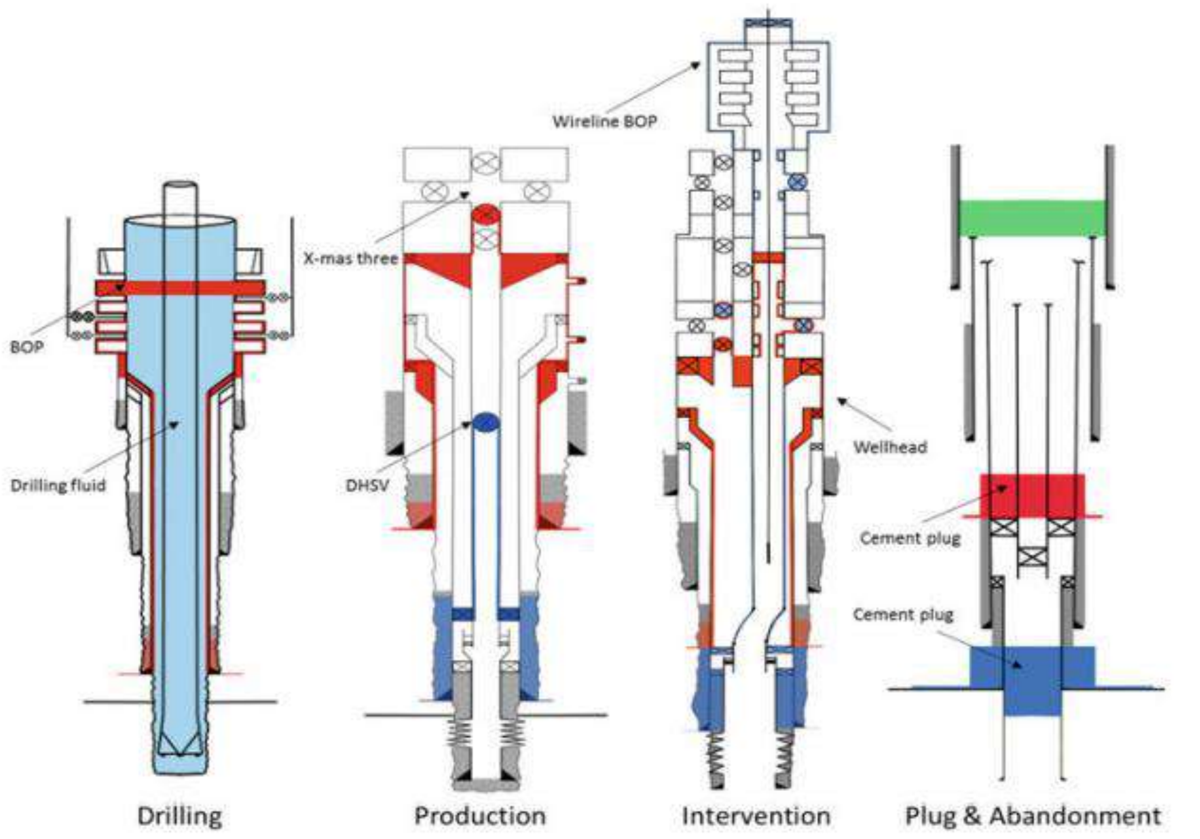


Figure I.1: Illustration of the two-barrier philosophy throughout a well's lifecycle (16).

Table I.1: Examples of barrier systems through the lifecycle of the well (14).

Example	Primary Barrier	Secondary Barrier
Drilling	Overbalanced mud with filter cake	Casing cement, casing, wellhead, and BOP
Production	Casing cement, casing, packer, tubing, and DHSV (Downhole Safety Valve)	Casing cement, casing, wellhead, tubing hanger, and Christmas tree
Intervention	Casing cement, casing, deep-set plug, and overbalanced mud	Casing cement, casing, wellhead, and BOP
Plug & Abandonment	Casing cement, casing, and cement plug	Casing cement, casing, and cement plug

1.5.1. Well Annuli:

An annulus is any void space between two strings, or a string of casing and formation. When a well is completed, different annuli might be distinguished. In well engineering, the annular space between production tubing and production casing is called A-annulus. The annular space between production casing and intermediate casing is called B-annulus. The naming procedure is continued until the last annular space, which is between the conductor and formation (see Figure. I.2). generally, these annuli should not have any connection to wellbore fluids. But the annuli are filled with completion fluid or drilling fluid for protection of steel and maintaining the pressure to ensure the integrity of the strings (15).

During coiled tubing well intervention operations, the annular space between the coiled and production tubing should be considered as an annulus and distinguished with a name.

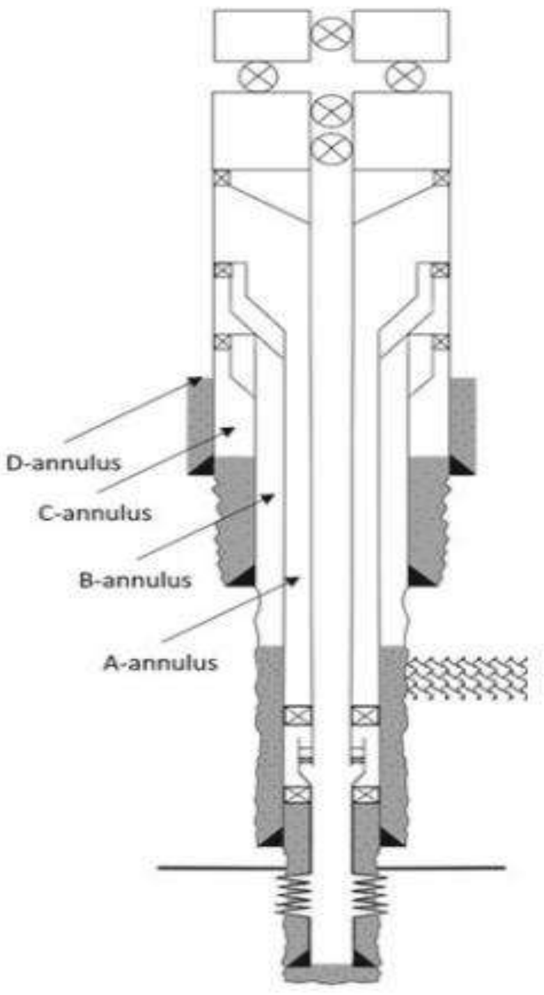


Figure I.2: Distinguished annuli in a completed well (14).

I.5.2. Well Barrier Envelope:

I.5.2.1. Primary and Secondary Well Barriers:

To understand the subject of well barrier philosophy, it might be beneficial to start with the following question: What is a barrier? The word barrier has its roots from Middle French barrier, which can be traced back to Anglo-French, from barre bar, in 14th century. Merriam-Webster dictionary defines barrier simply as “something (such as a fence or natural obstacle) that prevents or blocks movement from one place to another”. Different professional disciplines have established their version of the concept, in particular when it comes to operational and organizational barrier elements. Therefore, the term “barrier” is defined in many ways such as human barrier, non-technical barrier, operational barrier, non-physical barrier, or organizational barrier (17).In the context of well integrity, a barrier is an impenetrable object that prevents the uncontrolled release of fluid. Two-barrier philosophy considers two independent well barrier envelopes; primary well barrier and secondary well barrier. Primary well barrier is the first enclosure that prevents flow from a potential source of flow. Secondary well barrier is the second enclosure that also prevents flow from the potential source of inflow. The secondary well barrier is a back-up to the primary well barrier and it is not normally in use unless the primary well barrier fails. The principle of the two-barrier philosophy has already been shown in Fig. 1.1; primary well barrier shown as blue line and secondary well barrier as red. For situations where a formation with normal pressure is present, a one-barrier methodology could be acceptable for the abandonment design (14).

I.5.3. Well barriers failure (18):

Many different elements make up a well barrier, all of which need to be verified to confirm well integrity. The principle is maintained; however, the barriers and barrier elements vary to suit the risks and operational requirements of each phase. Well barrier design will vary between wells, influenced by the design of the well, the characteristics of the resource being drilled and the risks identified.

A well integrity failure occurs if all barriers have failed and there is a pathway for fluid to flow into or out of the well. In a two-barrier design, both barriers need to fail for a well integrity failure to occur. A barrier failure will not result in a loss of fluids to or from the environment provided that the second barrier is intact.

Well integrity issues can be caused by any of the following (10):

- A well breach, including failure of cement sheaths, plugs, bonds, casing, and downhole and surface sealing components,
- A hydrological breach, fluid movement between geological formations,
- Including formations not targeted for exploitation,
- An environmental breach. contamination of or water balance impact on water resources,
- Fluid leaks at surface and causes contamination of water sources. Various potential impacts on environments can result from poor oil and gas well integrity, such as:
- Impact on groundwater: contamination of shallow and deep aquifers could be a risk associated with oil and gas well drilling and production activities due to poor well construction,
- Localized hydraulic connectivity between isolated aquifers along a well trajectory, this can occur because of failed casing, poor cementing or generally poor well construction, decommissioning or abandonment practices,
- Fugitive gas emissions, localized gas leakage to both the atmosphere and into aquifers from oil and gas wells can occur because of equipment failure or poor well construction and abandonment practices.

I.5.4. Routes and driving mechanisms (19):

For a well to leak, there must be a source of fluid (see Figure I.3), a breakdown of one or more well barriers, and a driving force for fluid movement, which could be fluid buoyancy or excess pore pressure due to subsurface geology. There are seven subsurface pathways by which leakage typically occurs (Figure I.4 and I.5). These pathways include the development of channels in the cement, poor removal of the mud cake that forms during drilling, shrinkage of cement, and the potential for relatively high cement permeability. There are other mechanisms that can operate in specific geological settings. Reservoir compaction during production, for example, can cause shear failure in the rocks and casing above the producing reservoir; route 7 marked on Figure I.4. Leaking wells can also connect with pre-existing geological faults, enabling leakage to reach the surface. A range of fluids can leak, for instance formation fluids, water, oil and gas, and they can move through or out of the well bore by advective or diffusive processes. Overpressure may be the driving force for fluid flow (e.g. the Hatfield blow-out near Doncaster, UK), but hydrostatically pressured successions can also feed leaking wells, with fluids migrating due to buoyancy and diffusion.

A leak can be catastrophic, as seen in cases such as the recent blowout of a Whiting Petroleum Corp oil well and rare examples of explosions in urban areas, or be at sufficiently low rates to be barely detectable. The fluid sources can be hydrocarbon reservoirs (e.g. Macondo, Gulf of Mexico); non-producing permeable formations; coal seams; and biogenic or thermogenic gases from shallow rock formations. Oil or gas emissions can seep to the surface, though leaking methane can be oxidized by processes such as bacterial sulphate reduction. Well failures can potentially occur in any type of hydrocarbon borehole, whether it is being drilled, producing hydrocarbons, injecting fluid into a reservoir, or has been abandoned.

Wells can be tested at the surface for well barrier failure and well integrity failure by determining whether or not there is pressure in the casing at the surface. This is referred to as sustained casing pressure but does not necessarily prove which barrier has failed or its location. Channels in cement, which are potential leakage pathways, can be detected by running detection equipment down the borehole. Migration of fluids outside the well is established by inserting a probe into the soil immediately surrounding the well bore, or by sampling groundwater nearby, hydraulically down-gradient of the well. Poor cement barriers can be identified by a number of methods (e.g. ultrasonic frequency detection), and can be repaired in some cases, using cement or pressure-activated sealants (20).

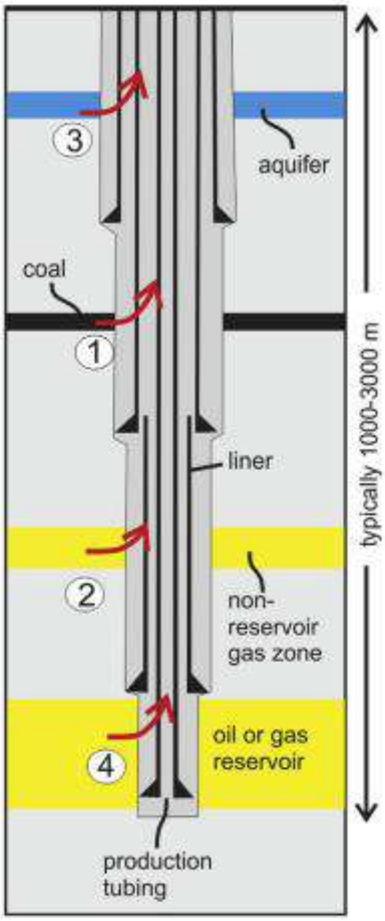


Figure 1.3: Schematic diagram of typical sources of fluid (19).

The Figure I.3 explains typical sources of fluid that can leak through a hydrocarbon well:

1- Gas-rich formation such as coal,

2- Non-producing, gas or oil bearing permeable formation,

3- Biogenic or thermogenic gas in shallow aquifer,

4- Oil or gas from an oil or gas reservoir.

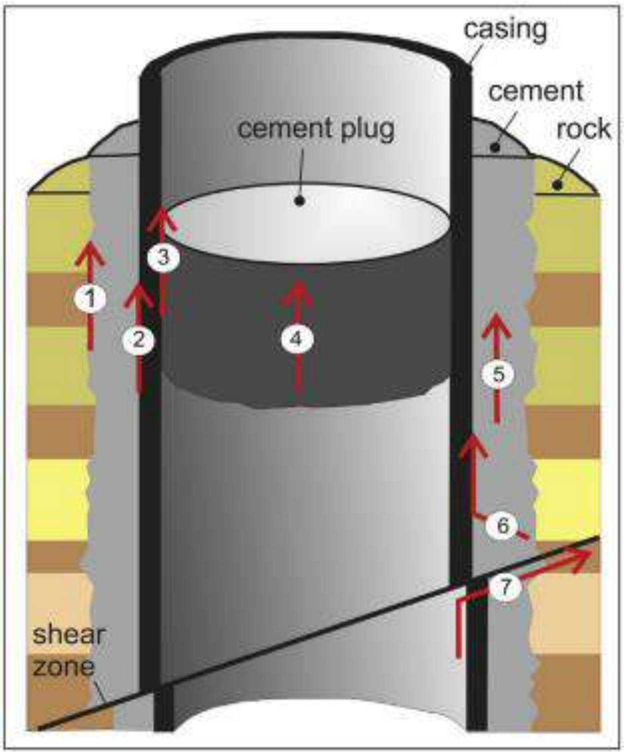


Figure I.4: Routes for fluid leak in a cemented wellbore (21).

Figure I.4 shows routes for fluid leak in a cemented wellbore where:

1- Between cement and surrounding rock formations,

2- Between casing and surrounding cement,

3- Between cement plug and casing or production tubing,

4- Through cement plug,

5- Through the cement between casing and rock formation,

6- Across the cement outside the casing and then between this cement and the casing,

7- Along a sheared wellbore.

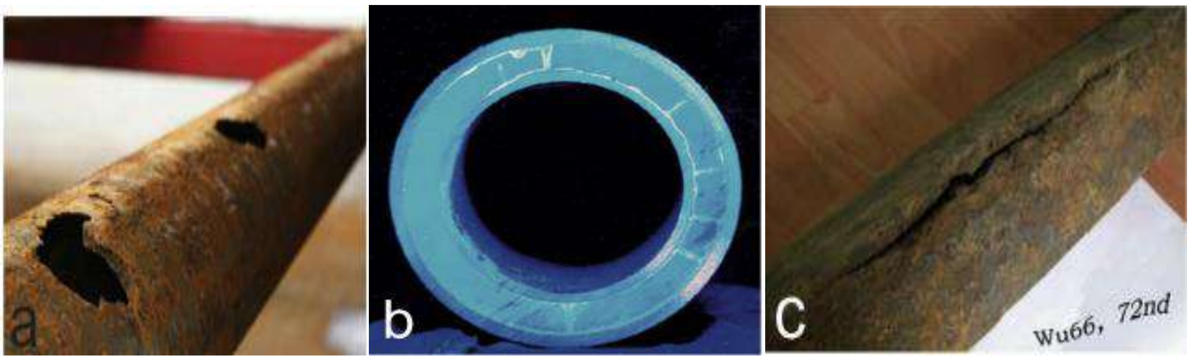


Figure I.5: Photographic examples of leak pathways (19).

Figure I.5 shows examples of leak pathways where:

(a)-Corrosion of tubing,

(b)- Cracks in cement,

(c)- Corrosion of casing.

I.6. Wellbore Integrity Issues:

I.6.1. Conventional and Unconventional Reservoirs:

Conventional reservoirs typically involve porous sandstone, carbonate, and shaly sand formations, whereas unconventional reservoirs include low porosity/permeability shales and sandstones, bitumen and heavy oil sands, and coalbed methane resources. Conventional and unconventional reservoirs share many typical well integrity challenges.

The most common well integrity issues involve fluid migration through leakage pathways. Various safety barriers are employed in wells to minimize potential leakage. Cement is another main hydraulic barrier apart from the fluid column which provides isolation between wellbore and formation fluid. However, cement has certain limitations such as chemical degradation and strength reduction with time. In addition, mechanical barriers can provide significant isolation of reservoir formations, and completed zones, from each other thereby reducing potential fluid loss and influx. Such barriers improve wellbore integrity and facilitate the transition from well completion to production. However, the performance of mechanical barriers has certain limitations, such as property degradation causing their strength to be altered over time and dynamic conditions. The complexity of many unconventional reservoirs poses many well integrity challenges such as severe pressure and temperature conditions, the irregular chemical behavior of formation rocks. Therefore, more comprehensive tactics are required to facilitate high-quality well integrity in the unconventional reservoir (22).

Unconventional shale reservoirs often encounter specific problems due to unpredictable geological behavior during drilling operations. Oil-based mud (OBM) is the most common drilling fluid used in these reservoirs.

The solubility of hydrocarbon gasses in OBM is considerable. This characteristic of OBM causes the evolution of dissolved gas when the mud reaches the bubble point pressure during circulation. This process provides a pathway for gas migration to shallower, uncased zones. This phenomenon can also result in sustained casing pressure in certain zones of a well during shale drilling operations. The robust casing can sustain the pressure differential between perforated zones and open hole, but in the case of an undetected leak, the pressure differential makes it difficult to set packers. Field observation in Marcellus shale indicates that sustained casing pressure mainly results from damaged cement rather than unset cement. Pipe whipping to casing during hydraulic fracturing is another common challenge in the unconventional reservoirs. This phenomenon potentially imparts additional force and stress to the cement resulting in cracks and the possible consequence of creating pathways for fluid migration. Such processes are constantly affecting the integrity of cement adjacent to the casing (23).

Gas-charged unconventional formations, particularly those at relatively shallow depths, such as coals, bitumen, and thin shale beds are classified as one of methane contamination sources in aquifers. One of the commonly used techniques to enhance the production of heavy oil and bitumen is enhanced thermal recovery. This technique reduces the viscosity, but it also induces thermal stresses which undermine the cement and cap rock integrity. Cement casing bond failure is prominent in these conditions due to thermal cyclic loading, casing buckling, and formation shear movements. Thermal cyclic loading typically results in extreme volumetric changes in the reservoir as a result of high temperature, cyclic dilation, fluid convection and contraction. Also, formation shear movements are mainly caused by in a reduction in friction due to heat transfer between the producing zones and thin surrounding impermeable beds (24).

Abnormally overpressure zones are created over geologic time scales due to the limited period for fluids to drain during the rapid burial of clay and shale formations in the sedimentary sequence. These zones can result in high annulus pressure. This high annulus pressure poses severe threat to well integrity pressure containment barriers. In addition, the cyclic stresses induced due to frequent change between production and injection accelerates the barrier degradation process and consequently leads to greater risk of casing deformation and collapse also, a combination of sand production and reservoir compaction is another challenge to casing integrity. Sand production depletes the lateral support, while reservoir compaction adds axial compressive load. This loading perturbation results into an extra load on the casing and makes it susceptible to buckling. Thermal stimulation in the Canadian oil sands, reservoir compressibility coupled with substantial pressure depletion in the Gulf of

Mexico Deepwater operations, compaction in the highly porous weak reservoir in the North Sea and California during production poses a significant threat to casing integrity (24).

Cavity completion incorporates repetitive injection of air or air/water mixtures into the wellbore. Following the injection stage, the surface valve is opened to reduce the pressure rapidly and suddenly, so that annulus is filled with the solid material, which is removed. This process is employed to potentially induce secondary fractures intersecting the natural fractures in the reservoir. However, the downside of cavity completion is its potentially adverse effect on cement and creation of connected leakage pathways between natural fractures and artificially induced fractures within the reservoir and surrounding formations (25).

I.6.2. High-Pressure and High-Temperature (HPHT) Wells:

High pressure and high temperature (HPHT) wells refer to the wells that have an expected wellhead shut-in pressure more than or equal to 690 bars (10000 psi) and/or wells with a temperature higher than 150°C (300°F). These prevailing high-pressure environments are conducive to fluid compression, which makes HPHT environment a suitable warehouse for oil and gas storage. However, HPHT wells pose high risks during drilling and completion operations. During drilling, these wells exhibit the coupling effects of changes in stresses, pore pressure and temperature, which often lead to wellbore instability problems, such as a tight hole, stuck pipe, and differential sticking. The elevated temperature tends to decrease the equivalent circulating density (ECD) of the mud, due to thermal expansion, and consequently, narrows the margin for the fluid influx from the formation. This reduction in ECD will make the well more susceptible to kicks or collapse. Also, HPHT conditions reduce the thickening time of cement slurry, which accelerates the development of premature compressive strength and can promote cracking in post-set cement. The rheological properties of cement, such as plastic viscosity and yield point, drops significantly which affects the wellbore pressure profile. In the absence of an accurate prediction of the wellbore's pressure profile, the casing and cement sheath may be unable to withstand the formation pressure potentially resulting in wellbore collapse. At temperatures above 450o F, cement sets within a fortnight, but due to the formation of porous structure, Tobermorite exhibits strength retrogression (26).

HPHT wells exhibit higher pressure differentials inside the casing and formation over the production life than conventional wells. Therefore, several other challenges such as casing eccentricity, channeling in cement, and cement voids are often associated with these environments. Ichim and Teodoriu have shown that casing eccentricity will increase the local stresses on cement increasing the chance to fail. Casing eccentricity results in non-uniform fluid velocity, which circumvents slow moving drilling fluid and leads to irregular cement work undermining the well integrity. Studies demonstrate that voids in cement and cement channeling have a higher impact on casing collapse resistance than casing eccentricity. Consequently, this behavior of casing affects the mechanical properties of the cement casing sheath behavior overall. The cement exhibits higher tensile failure probability in channeling condition, while higher compressive failure probability in situations involving casing eccentricity (25).

I.6.3. Deepwater Drilling:

Deepwater drilling introduces multiple additional risks and complex challenges compared to conventional onshore and shallow water drilling. For instance, deepwater environments typically contain gas hydrate zones at shallow depths below the seabed. Typically gas hydrate zones are associated with over-pressured sand formations. Drilling through these zones can lead to exposure to high-pressure fluid flows that can compromise the structural integrity of the well, and consequently result in buckling and failure of the casing. Ultimate consequences of this failure include wellbore collapse and/or leakage pathways created along the cement-casing interface. In addition, such failures can induce fluid flow from formations, which have the potential to result in the uncontrolled discharge of formation fluids and blow-outs. In Deepwater environments, this type of flows is difficult to predict and prevent. Heat development during cement hydration can also lead to hydrates destabilization and loss of well integrity (27).

Salt formations, encountered during Deepwater drilling in many locations, pose several critical well integrity issues during drilling, completion, and throughout the well life cycle. Salt formation locally alters the stress fields and complicates the wellbore stability while drilling by imposing non-uniform forces, which can be tensile or compressible in nature. Salt is a relatively ductile and easily deformed rock formation in the subsurface, progressively moving and flowing over geologic time scales. Progressive deformation of salt formations post drilling increases the risks of the casing collapse during the production phase of wells drilled through it because the salt formation imparts varying lateral forces on the casing. Also, the wellbore temperature profile impacts the behavior of salt formations. The change in temperature between the top and bottom of salt formations creates differential creep rates between the sections and consequently, creates enormous differential stresses (23).

This differential stress severely impacts the wellbore's cement and casing integrity, resulting in cracks in the set cement or fluid migration pathways created along cement-casing interface or formation-cement interface. Also, the effect of casing eccentricity caused by fast creeping stress results in a severe alteration in casing bearing stress in the salt zones over the life of the wells. Recently, it has been found out that the salt formation poses non-uniform casing and cement load, which has been very little studied in the past (25).

I.7. Well barrier integrity failure mechanisms:

This section discusses mechanisms for oil and gas well barrier failure in major phases of a production well life cycle. It also briefly discusses the likelihood of these failure mechanisms occurring, and the consequences and the mitigation measures required if they should do so (28).

I.7.1. Failure mechanisms associated with oil and gas well drilling:

Drilling, the first step in constructing a well, presents a number of potential risks to well integrity. During drilling, the primary well barrier is the drilling fluid pressure exerted on the rock formation surrounding the well. The secondary well barrier includes the drilling blowout preventer, casing and cement, well head and cap rock formation.

Drilling fluid density or mud weight is vital in maintaining well integrity before the casing is cemented. A safe mud weight range (or window) is determined by a lower bound (defined by the formation pore pressure) and an upper bound (defined by the formation fracture gradient). If the mud pressure is less than the formation pore pressure, formation fluid may enter the well. Uncontrolled influx of large volumes of hydrocarbons may lead to a blowout at the surface, which may in turn have a significant impact on the environment. Low mud weight can also result in wellbore instability (breakout or washout; that is, enlargement of borehole size). This is not a direct risk to well integrity in terms of containing and controlling the flow of wellbore fluids. However, the significantly enlarged wellbore may result in poor displacement of mud during cementing and therefore a poor-quality cement sheath behind the steel casing, which may lead to loss of well integrity (28).

If the mud weight is greater than the formation fracture gradient, drilling fluid may enter the surrounding formations or reservoirs. Most drilling fluids currently used in Australia are water based, generally comprising a mixture of water, clays, fluid loss control additives, density control additives and viscosifiers. If large volumes of drilling fluid are lost into overburden or the reservoir (in particular, into shallow aquifers), this can significantly affect the environment.

To reduce risks of blowout or massive loss of drilling fluid during drilling, formation pore fluid pressure along the well trajectory is estimated. The estimate is based on data from nearby oil and gas wells or a seismic survey before drilling. Leak-off tests are conducted to ensure the integrity of casing and cement, and to determine the formation fracture gradient. A functional BOP will significantly reduce or eliminate the risk of environment contamination due to blowout. Because of the low permeability of shale gas reservoirs, significant hydrocarbon blowout from shale gas reservoir is unlikely during drilling (10).

I.7.2. Failure mechanisms related to casing and cementing (29):

Well integrity can be lost though casing and cementing issues such as channels or voids in the cement; gaps between the formation and the cement, or the cement and the casing; and pore adhesion. These issues can be caused by poor placement of the cement, leakage through casing connections, degradation of the cement sheath and corrosion of the casing.

If channels of drilling mud remain in the annulus, they may provide a preferential flow pathway for fluid to migrate inside the cement sheath. If a build-up of compacted drilling mud (also referred to as filter cake) is left on the well surface before cementing, it could dehydrate after the cement sets, resulting in an annulus at the interface of the formation and the cement. Furthermore, cement can shrink during setting, resulting in a microannualus (a fracture between the cement and the casing or formation) along the interface between the cement and the casing, or between the cement and the formation rock.

A good cement sheath is a solid that has a low permeability (measured in microdarcies) and hydraulic conductivity (that is, in the order of 10-6 m/d), 54 and that bonds to the casing and formation surfaces. Such a sheath prevents fluid from migrating within or through the sheath. However, downhole pressure and temperature can change because of operations in the well's history, such as casing pressure tests, well production and shut-in, and reservoir hydraulic fracturing stimulation. These operations lead to changes in well pressure and temperature, which in turn can induce radial deformation of the casing and failure in the cement sheath. This can lead to debonding on the interfaces between the cement sheath and the casing or formation, creating migration pathways through radial fractures and micro annuli.

The impact of the cement sheath and bond failure on well integrity will depend on the extent of such failure along the wellbore and on specific geological conditions. For example, one study in the Gulf of Mexico found that there was no breach in isolation between formations with pressure differentials as high as 97 MPa (14,000 psi), provided there was at least 15 m (50 feet) of high-quality cement seal between the formations.

The risks of the well integrity being compromised due to well casing and cementing can be mitigated by (10):

- Setting the surface casing well below the base of the aquifer system,
- Designing a cement slurry that is appropriate for the geological and geochemistry conditions,
- Completing the coverage of the hydrocarbon bearing formations with cement in the well annulus,
- Selecting materials for casing and other well barrier components that are compatible with the geochemistry environment,
- Applying good industry cementing practice,
- Using wireline logging tools to check the quality of cement sheath and bonds on the interfaces and mediatory cementing.

I.7.3. consequences of failure of well integrity:

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.

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, but keeps in mind that any other element like a wrong operational decision may lead to well integrity issues (3).

I.8. Requirements for Risk Assessment:

I.8.1. Risk Assessment characteristics (3):

It is useful to perform risk assessments in different contexts; such as a tool for decision support from engineering and financial points of view, or as a means to identify, control and document HSE risks.

In general, the purpose of a risk assessment is to execute a process that gathers and assesses information about what may happen and why, how measures (changes or already implemented) can influence what may happen, and what is acceptable.

A risk assessment should cover:

- Assessment of the well integrity (technical, operational and organizational) during its life cycle,
- Both production and injection wells (doublet),
- The source, pathway and receptor components. The most relevant consequences to consider are:
  - Serious damage to human health, safety and the environment (ecosystem), and in particular related to substances mentioned in the legislation,
  - Impact on equipment/system performance,
  - Communication and reputation,
  - Financial,
  - Whether the Geothermal well contains either hazardous waste or dangerous substances.

I.8.2. Well integrity considerations for the life-cycle of a well (30):

The focus of well integrity issues of importance varies with the different life-cycle phases. During the well design phase, less data is available describing the formation and reservoir properties, and what is available is subject to potentially large uncertainty. Reliability in information relating to subsurface pressures (pores and fracture pressures), borehole stability, geothermal temperature, lithology and fluid characteristics all possess a degree of uncertainty, ultimately impacting the design of the well.

During the **well construction phase**, the main KPI (Key Performance Indicator) is often the time vs. depth curve, and to a lesser extent well integrity KPIs. However, from a well integrity perspective it is essential that control mechanisms exist, both prior to cementing and after as well as during the completion stage, to verify the validity of the planned design in light of measurements and data obtained during well construction.

Casing design is a crucial component of the integrity of any well, and there are a number of considerations in this respect. Ac. these include maximum allowable setting depth with regards to kick margin, pore pressure development and formation strength, drilling fluid and cement program, induced loads, H2S potential, circulation density, isolation of weak formations, potential loss zones and geo-tectonic forces. For high temperature wells particular considerations must be made for thermal expansion of steel and trapped fluids, weakening of the casing through temperature cycling, and presence of corrosive well fluids.

The integrity of the casing as a barrier element may be degraded during the drilling phase. The use of abrasive coating materials on drill pipe tool joints may wear the casing. Wear of casing also arises from the longer contact time between the casing and drill pipe tool joint due to low rate of penetration (ROP) and high revolution per minute (RPM).

In the **production phase**, the risk of corrosion is one of the main concerns due to a greater exposure to formation fluids. Another important aspect is that until the production commences, the well is the responsibility of the drilling department. The change in responsibility when moving into another life-cycle phase, implies the importance of a proper handover, to ensure that all important well-specific concerns, including those relating to well integrity, are transferred to the production department. This pertains not only to data transfer, but also to training and re-evaluation of the risk assessments conducted during the previous life-cycle phases, involving personnel from the production department.

The challenges in **the abandonment phase** can often relate to the fact that data on the well has been handed over multiple times, and gaps in data and/or inadequate handover may lead to poor decisions being made relating to risk management and well integrity. Issues, such as sustained casing pressure, that have been circumvented through dispensations in the production phase, may cause problems in the abandonment phase when attempting to verify barrier integrity, as restoration of e.g. annulus barriers is difficult.

An updated well evaluation, including cement bond logs etc., and abandoning the well in accordance with local regulations, as is industry practice, can help overcome such challenges (3).

I.9. well integrity management:

I.9.1. Background of well integrity management:

In the 2006 well-integrity-survey, phase-1-summary report, the PSA recommended: "….that the operating companies review their in-house management systems for compliance with the requirements in the regulations for barriers and how this is distributed and actively used internally in order to reduce the chances for any incidents". This was the basis for one of the initial items on the WIF task list upon being organized in 2007 which was to investigate the need for a Norwegian, oil-industry guideline covering the management of well integrity.

As has been common practice with the WIF on previous projects, a review was conducted of the WIF-member-companies' efforts towards managing the integrity of their wells. Then a review of the various regulations (Framework, Management, Information Duty, Facilities and Activities) and Norsok D-010 standard (chapters 4 and 8) was completed and all aspects applicable to well integrity were summarized. Based on this review, the items have been grouped into the following categories: Organization, Design, Operational Procedures, Data and Analysis. These categories form the basis of the guideline (31).

I.9.2. Elements in a Well Integrity Management System (31):

A well-integrity-management system should be the complete system necessary to manage well integrity at all times through the life cycle of the well. The system could be grouped into 5 main elements: Organization, Design, Operational Procedures, Data System, and Analysis. The relation of these elements is illustrated in the figure I.6 below:

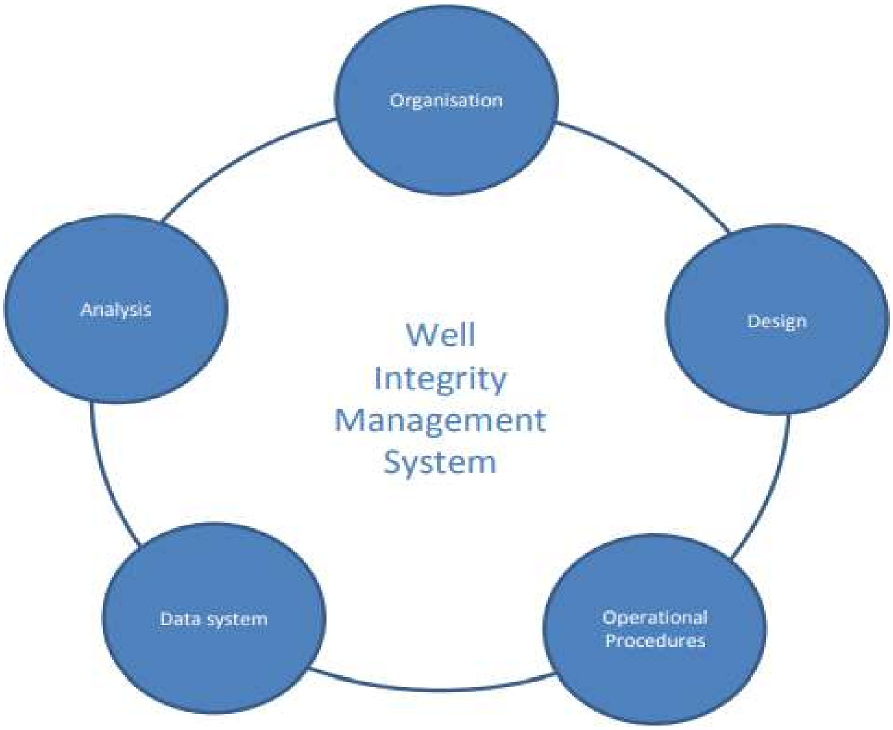


Figure I.6: Well Integrity Management System (31).

Even though the regulations have some well-integrity-specific requirements, most of the integrity-management regulations are general in nature.

I.9.3. Well Integrity Management Processes (32):

Typically well integrity management processes must span the well's full life cycle as illustrated in the figure I.7.

We often find that companies with well integrity management concerns either do not have clear processes or have failed to implement them properly. Alternatively, they may have valid processes but these may not have been updated for many years, or may not even be compliant with industry standards such as ISO/ TS-16530 "Well Integrity Technical Specifications" and "NORSOK Standard D-010", thus reducing their overall effectiveness.

Partly because some regulatory regimes are not stringent enough, the reason for these process-related concerns also reflects the fact that, until Macondo, well integrity assurance has often not had the same level of attention given to it as asset2 integrity assurance, which has attracted significant effort over many years. Well integrity processes are therefore still evolving in many organizations, with only those having a portfolio of very old wells, or wells with other integrity issues, having generally recognized the importance of setting up coherent well integrity management processes.

Such a lack of effective well integrity processes will reduce the confidence of the Asset Owner (Operations Group) when taking over wells from Drilling Groups after either drilling or workover and could significantly increase the number and frequency of workovers, thus impacting revenue and costs.

In extreme cases this might lead to an uncontrolled release of hydrocarbons, resulting in regulatory agency penalties and a detrimental impact on shareholder value.

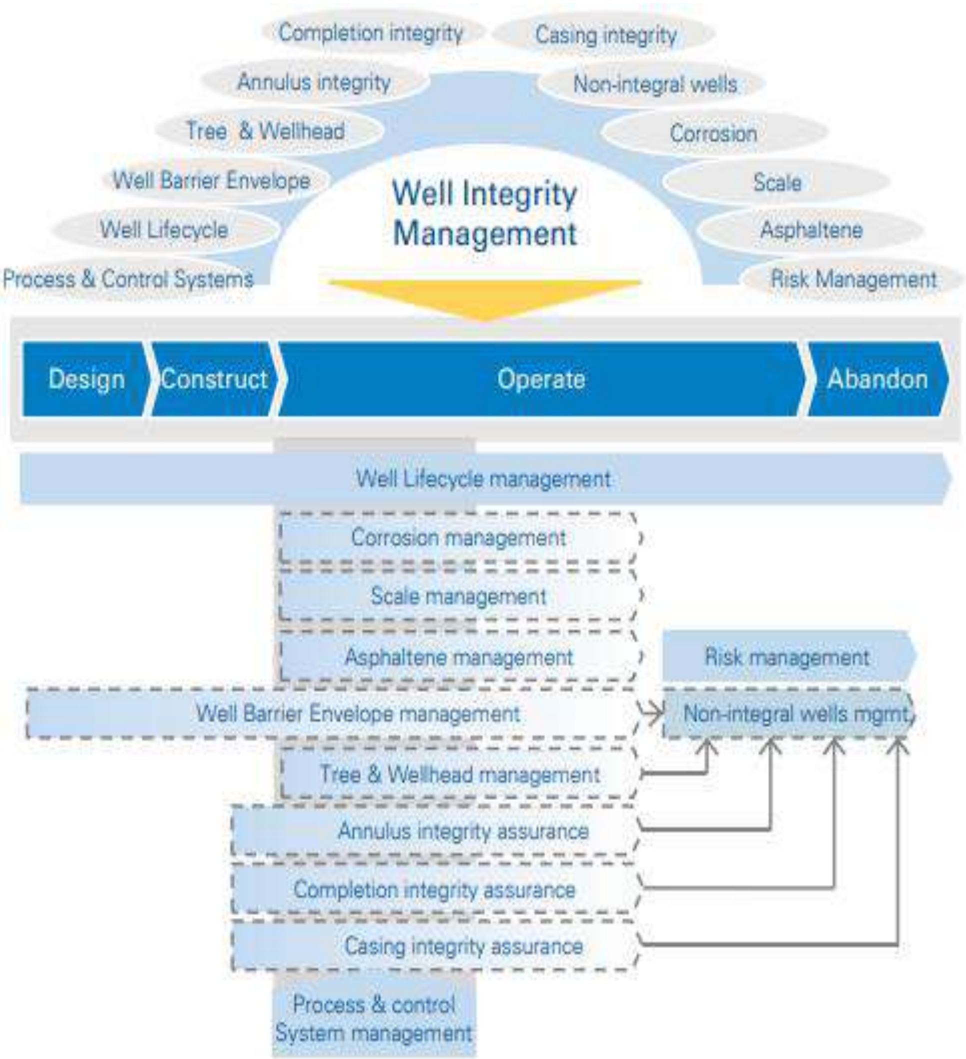


Figure I.7: Well Integrity Management Processes (32).

CHAPTER TWO

INTEGRITY OF CASING AND CEMENT

II.1. Introduction:

An oil and gas well is drilled in sections from the surface to the production zone. It is not possible to drill the well in one section due to the difference in formations properties. Each section of formation, after being drilled, has to be sealed off by running a steel pipe called casing. The casing string is consisted of pipe joints, of approximately 40ft in length with threaded connections. The annular space between the casing and the borehole is filled with cement.

Cementing is a very common operation carried out during the construction phase of the majority of oil wells. The idea of cementing operations can be traced back to 1859 and 1871, with the first cement operation executed in 1883 by Hardison & Stewart Oil Company. Cementing operations have two main objectives. The first objective is to provide well integrity by controlling flow in the well through hydraulic isolation between different zones in the wellbore. Thus, successful cementing prevents fluids from geological formations flowing into other geological zones or to the surface. The second objective is to provide support for the casing.

II.2. Generality of casing and cement:

II.2.1. Casing:

Casing has a main role in the ultimate well cost. Therefore, selecting the suitable casing type (length, grade, and size) is very important based on the requirements and geological data, casing has numerous performances in a well including (33):

- Isolation of the well fluids from formation and formation fluids,
- Preventing of borehole collapse while drilling,
- Offering a clear pathway to the drilling fluid,
- Minimization of the damage to the subsurface environment.

II.2.1.1. Casing types:

There are five types of casing as illustrated in Figure II.1.

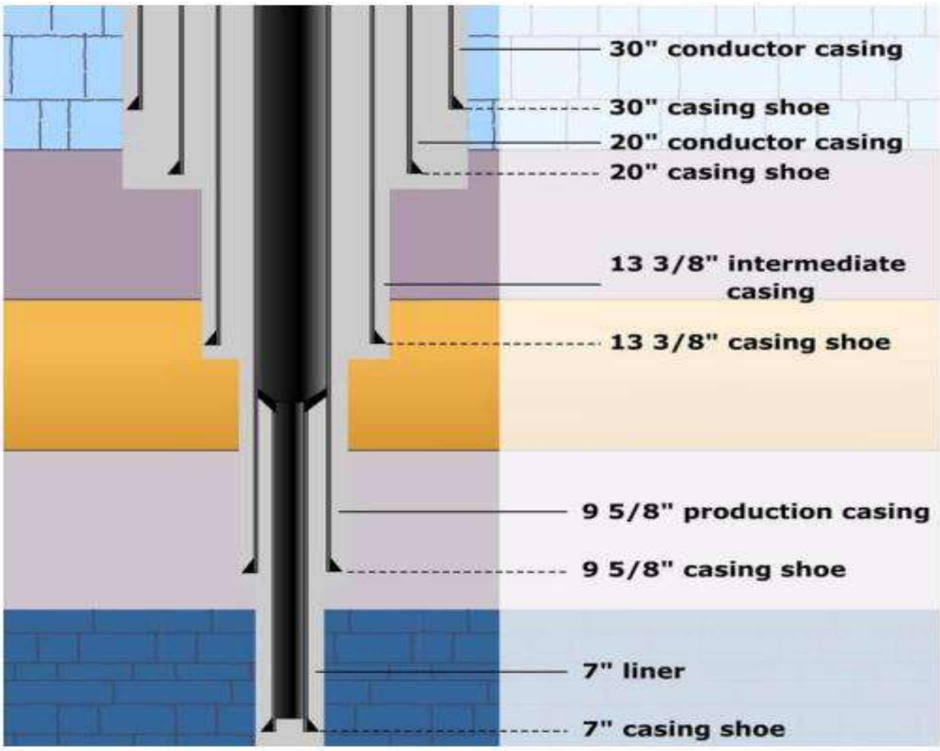


Figure II.1: Types of casing (33).

II.2.1.1.1. Conductor casing:

It is the first and largest casing to be run. It is generally set at 100 ft below the ground level. The main function of setting the conductor pipe is sealing off the unconsolidated formations which are near the surface. These formations can be easily washed out with continuous mud circulation; also they are characterized with low fracture gradient which can be exceeded by the hydrostatic pressure generated by the drilling fluids (33).

II.2.1.1.2. Surface casing:

The function of this type of casing is sealing off the fresh water zones and providing a support for the blowout preventer (BOP). The setting depth of this casing has to be accurately designed in areas where high pressure is expected. If the surface casing is set higher than planned or the setting depth is underestimated, the formation at casing shoe cannot resist to the pressure exerted while circulating gas influx which can occurs during drilling the next section (33).

II.2.1.1.3. Intermediate Casing:

Intermediate or protective casing is set at a depth between the surface and production casings. The main reason for setting intermediate casing is to case off the formations that prevent the well from being drilled to the total depth. Troublesome zones encountered include those with abnormal formation pressures, lost circulation, unstable shales and salt sections (34).

II.2.1.1.4. Production Casing:

Production casing is set through the prospective productive zones except in the case of open-hole completions. It is usually designed to hold the maximal shut-in pressure of the producing formations and may be designed to withstand stimulating pressures during completion and workover operations. It also provides protection for the environment in the event of failure of the tubing string during production operations and allows for the production tubing to be repaired and replaced (34).

II.2.1.1.5. Liners:

A liner is a string of casing that does not reach the surface. Liners are hung on the intermediate casing by use of a liner-hanger as illustrated in Figure II.2. In liner completions both the liner and the intermediate casing act as the production string. Because a liner is set at the bottom and hung from the intermediate casing, the major design criterion for a liner is usually the ability to withstand the maximum expected collapse pressure (35).

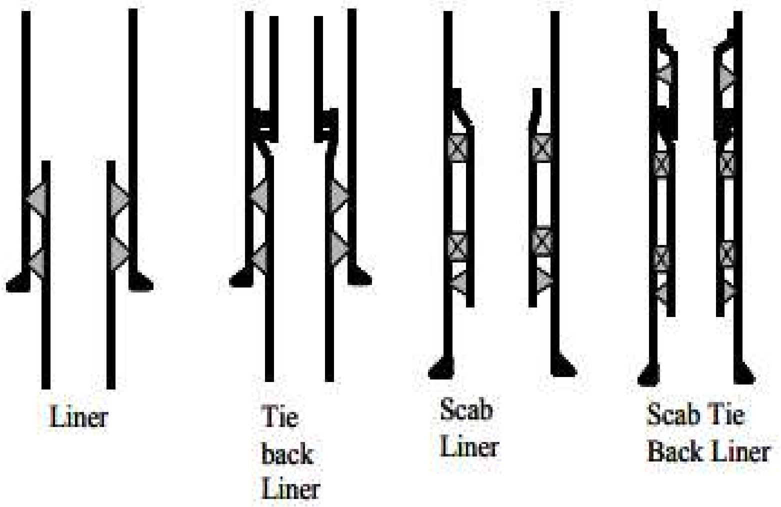


Figure II.2: Types of Liners (35).

II.2.1.2. Casing Strength properties:

For casing design, there are three main loads which have to be considered:

- The yield strength,
- Collapse pressure,
- Burst pressure,
- Tension,
- Biaxial effect.

II.2.1.2.1 The yield strength:

Yield strength is defined as tensile stress which produces the 0.5% elongation per unit length of casing specimen. This value varies according to the steel alloy used to make the casing joint. Couplings have also their yield strength which can be higher or lower than the main body yield strength. The manufacturer supplies data for both: main body and the coupling (33).

II.2.1.2.2 Collapse pressure:

Collapse pressure originates from the column of mud used to drill the hole, and acts on the outside of the casing. Since the hydrostatic pressure of a column of mud increases with depth, collapse pressure is highest at the bottom and zero at the top (35).

Collapse pressure can be calculated by the two equations below (Equation 2.1 and 2.2).
Collapse pressure = External pressure – Internal pressure 2.1

Collapse pressure (C) = mud density x depth x acceleration due to gravity

C = 0.052 x ρ x CSD….psi 2.2

II.2.1.2.3 Burst pressure:

Burst pressure is based on maximum formation pressure expected during drilling of next hole section. It is also assumed that in the event of a kick, the influx fluid(s) will displace the entire drilling mud, subjecting the entire casing string to the bursting effects of formation pressure. At the top of the hole the external pressure due to the hydrostatic head of mud is zero and the internal pressure must be supported entirely by the casing body. Therefore, burst pressure is highest at the top and least at the casing shoe. Hence if some part of production casing at top is not cemented, burst pressure can be a significant failure contributor (36).

Burst pressure can be calculated by the two equations below (Equation2.3) and (Equation 2.4).

$$\text{Burst pressure} = \text{internal pressure} - \text{external pressure} \qquad 2.3$$

$$P_{br}=0.875*((2\sigma_y \div (d_0 \div t)) \qquad 2.4$$

Where:

σ_y : Yield strength
d_0 : outer diameter of casing
t : thickness of casing

II.2.1.2.4 Tension:

Tensile forces in casing are due to combined buoyant weight, shock load and pressure test. In casing design, the top most joint is considered weakest in tension (as it must carry the total weight of casing string). In the thesis, the casing liner hanger is the weakest point and is assessed for the tensile forces. The casing hanger provides support for the casing string when it is lowered into the wellbore. It serves to ensure that the casing is properly located. When the casing string has been run into the wellbore it is hung off, or suspended, by a casing hanger, which rests on a landing shoulder inside the casing spool. Casing hangers provide a seal between the casing hanger and the spool and are usually part of the secondary well barrier. It is usually welded or screwed to the top of the surface casing string (36).

II.2.1.2.5 Biaxial Effect

Axial tension reduces the collapse resistance. Hence there is a reduction in collapse strength in upper part of string due to weight hanging below. Biaxial stress reduces collapse resistance of the casing in plastic failure mode (36).

II.2.1.3 Casing Wear (14):

Casing wear is often a problem in deep and highly deviated wells where doglegs and large tensile loads on the drill string combine to produce high lateral loads where the drill string contacts the casing. It is a complex process involving variables such as temperature, drilling fluid type, percentage of abrasives in the drilling fluid, tool joint hard facing, revolutions per minute, tool joint diameter, contact load, and many other factors. In the course of P&A operation, casing wear can compromise.

The integrity of casing and result in blowouts, lost circulation, and other expensive and hazardous problems. Therefore, it is necessary to measure and analyze the casing wear that has occurred over the lifetime of a well (e.g. during construction and intervention operations) and consider it in the abandonment design. The risk of induced casing wear while the P&A operation is performed also needs to be studied in the abandonment design.

II.2.1.4 Casing Corrosion:

This can have an effect on metal loss if a continuous feed of hydrocarbons containing CO_2 and / or H_2S is introduced into an annulus. However a leak path from tubing to annulus will normally allow only a small quantity of hydrocarbons to be introduced at any one time. There then exists effectively a static annulus condition which results in more protective corrosion films than the corrosion models suggest, but reliable information to verify this is scarce. Corrosion due to oxygen ingress at surface can be a significant problem, this is normal mitigated by the use of corrosion inhibitors and oxygen scavengers in the completion fluids or positive pressure in the annulus (37).

II.2.1.5 Casing Shoe Strength:

The casing shoe has an importance and special measurement and procedures to guaranty the well integrity. The determination of CSS is already a part of designing drilling and well completion operation. Finding subsurface failure of a well due to sustained casing pressure requires knowledge of casing shoe strength (CSS) at the casing depth. Planning of mud weight window, decisions for casing setting depths for the next interval, calculation of kick tolerances and design of fracture operations all require accurate knowledge of the maximum

pressure that the casing shoe would withstand. Weight of the overburden and reservoir pressure mainly create the in situ stresses.

The Measurement of Casing Shoe Strength take by consideration of formation test, extended leak off test (XLOT) has been also developed to determine the integrity of shallow casing shoes and its interpretation is more complex (38).

II.2.1.6 Lost circulation (35):

If collapse calculations are based on 100% evacuation then the internal pressure (or back-up load) is to zero. The 100% evacuation condition can only occur when:

•Casing is run empty,
•There is complete loss of fluid into a thief zone (say into a cavernous formation),
•There is complete loss of fluid due to a gas blowout which subsequently subsides.

None of these conditions should be allowed to occur in practice with the exception of encountering cavernous formations.

During lost circulation, the mud level in the well drops to a height such that the remaining hydrostatic pressure of mud is equal to the formation pressure of the thief zone. In this case the mud pressure exactly balances the formation pressure of the thief zone and fluid loss into the formation will cease. If the formation pressure of the thief zone is not known, it is usual to assume the pressure of the thief zone to be equal to 0.465 psi/ft, this is the pore pressure of normally pressured zones where the pressure is hydrostatic. Normally pressured zones are assumed to be connected to the sea or to a large aquifer with normal pressure.

II.2.2. Cement:

For the majority of people, cement is associated with the construction industry. However, cement is also widely used in other industries. In the petroleum industry for instance, cement is the most important oil well binding material in terms of quantity manufactured. Cement is one important well barrier element which is present between the formation and the casing as well as a plug after plug and abandonment (P&A) operations. In order to provide zonal-isolation and prevent hydrocarbons from flowing behind the casing to weaker zones or to surface, cement is pumped down the annulus through the casing shoe and up the annular space between casing and formation. Ideally, the cement mixture is developed to provide low permeability matrix and thereby isolate the well during drilling, production and further until the well is abandoned. Unfortunately this is not always the case, due to several influencing factors and downhole conditions. The annular cement sheath may fail throughout the life time of the well and thereby cause loss of well integrity.

There are many reasons for pumping cement slurry while drilling operations, the most important functions are (39):

- Preventing fluids flow from one formation to another or to the surface. The fluids can flow between the casing and the formation,
- Bonding the casing to the formation,
- Supporting the casing string,
- Protecting the casing from the corrosion caused by formation fluids,
- Sealing off the troublesome zones.

II.2.2.1. Classification of Oil Well Cements (40):

Oil-well cements are usually made from Portland cement clinker or from blended hydraulic cements. Initially, only one or two types of oil well cement were available. As oil/gas wells became deeper and subjected to more adverse environments, the more stringent performance criteria could not be satisfied by those cements. With the advent of the API Standardization Committee in 1937, improved OWCs were developed. The API Specifications for Materials and Testing for Well Cements include requirements for eight classes of OWCs (classes A through H). OWCs are classified into grades based upon their C3A (Tricalcium Aluminate) content: Ordinary (O), Moderate Sulphate Resistant (MSR), and

High Sulphate Resistant (HSR). Each class is applicable for a certain range of well depth, temperature, pressure, and sulphate environments.

Class A, Class G and Class H are the three most commonly used oil well cements. Class A is used in milder, less demanding well conditions, while Class G and H cements are usually specified for deeper, hotter and higher pressure well conditions.

API Class G and H are by far the most commonly used OWCs today. The chemical composition of these two cements is similar. The basic difference is in their surface area. Class H is coarser than Class G cement and thus has a lower water requirement.

II.2.2.2. Rheology of Oil Well Cement Slurries (40):

The rheological properties of an oil well cement (OWC) slurry determines the quality of the final product and helps predicting its end use performance and physical properties during and after processing. Rheological measurements can determine the flow properties of the cement slurry such as its plastic viscosity, yield point, frictional properties, gel strength, etc.

II.2.2.3. Thixotropic cements (41):

A thixotropic system is fluid under shear, but develops a gel structure and becomes self-supporting when at rest. In practical terms, thixotropic cement slurries are thin and fluid during mixing and displacement but rapidly form a rigid, self-supporting gel structure when pumping ceases. Upon reagitation, the gel structure breaks and the slurry regains fluidity. Then, upon cessation of shear, the gel structure reappears and the slurry returns to a self-supporting state. This type of rheological behavior is continuously reversible with truly thixotropic cements.

Thixotropic cement systems have several important applications. They can be used in wells in which excessive fallback of the cement column is a common occurrence. Such wells have weak zones that fracture under low hydrostatic pressure, allowing the cement slurry to invade the formation. Self-supporting cements reduce the hydrostatic pressure on the formation as gel strength increases and prevent fallback. Another important application is the prevention of lost circulation during placement. When thixotropic slurry enters the thief zone, the velocity of the leading edge decreases and a gel structure begins to develop. Eventually, the zone becomes plugged because of the increased flow resistance. Once the cement sets, the zone is effectively consolidated.

II.2.2.4. Causes of Failed Cement Sealing Ability (39):

Several aspects may influence cement sheath integrity. These will create weak paths for formation fluid to flow into other geological zones or up to surface, leaving the surrounding environment in danger for contamination, and expose working personnel to dangerous situations. The weak paths created within the cement are often referred to as micro annuli, represented by debonding between casing and cement, formation and cement, radial cracks, tangential cracks or sliding cracks see Figure II.3. In addition, cement sheath integrity can be affected by mud channels within the set cement. Here formation fluid will move freely within the mud channel towards lower pressure formations.

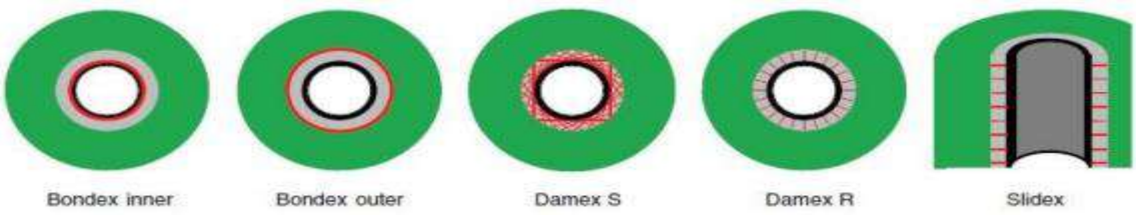


Figure II.3: Potential well paths and failures in zonal cement sheath (39).

II.2.2.5. Cement Shrinkage (39):

Whenever water and Portland cement powder react with each other, an exothermic hydration process (meaning that heat is released) is initiated. Gel of hydrated material form (C-S-H gel), followed by precipitation of hexagonal calcium hydroxide (C-H) plates. Moreover, as the hydration process continues, the gel structure binds the different compounds in cement making a set solid structure, which gives cement its beneficial properties.

II.2.2.6. Cement-Casing Debonding (39):

The strength of the cement to casing bond is frequently referred to as shear-bonding strength. Tests performed by Evans and Carter (1961) present a correlation between compressive strength and shear-bond, indicating improved shear-bonding with increased cement compressive strength. However, these tests were conducted under ideal settings with clean dry pipe and with no internal casing pressure. By altering testing conditions, shear-strength showed different characteristics. Rough casing surfaces as rusty, brushed or sandblasted increased the bonding strength when compared to new pipe. The effect of drilling mud was also tested. Casing exposed to drilling mud showed detrimental effects on the bonding strength.

II.2.2.7. Cement-Formation Debonding (39):

The outer boundary within a cement sheath is less predictable and more difficult to map by well logging. It is even hard to get information on the cement-formation bond when recovering casing strings in problem wells.

Investigation of the cement-formation bond by testing cement interaction with mud cake. This revealed important results, indicating dehydration of the filter cake by cement. The alteration of water content in the in-situ clay minerals affected the cements hydration rate unfavorably, leading to slower development of CSH-gel, and thereby delay setting time of cement. Tests with different drilling fluids were also conducted: Oil-based, silicate-based and potassium chloride-polymer-barite filter cakes were performed, which gave unlike results.

II.2.2.8. Radial Cracking, Sliding and Disking (42):

Mechanical cracking of the cement sheath may occur in several ways due to induced stress regimes. Compression stresses or tensile stresses may create micro annuli for formation fluid migration, leading to loss of well integrity.

The imposed stresses are often resulted by temperature and pressure variations. An increase in pressure will for instance lead to radial cracking in case of weak in-situ wellbore formation, since cement is stiffer than the formation (higher Young's Modulus). If the cement is more resilient shear damage development is favored. A decrease in pressure as mentioned earlier will lead to debonding between cement and casing interface. Increase and decrease of downhole temperatures will also impose radial and shear cracks. In addition, tectonic stress and formation creep may cause the cement sheath to fail as well. Faults, compaction of formation and formation creep expose the cement to high loads. Here, ductile cement is preferred to withstand high loads and support the casing from oval deformation and buckling. When cement can't slide at its inner or outer boundaries sliding or disking may take place. Leading to loss of radial well integrity and thereby weakening the cement sheath.

II.2.2.9. Chemical Degradation of Cement (39):

Over time as cement systems are exposed to surrounding environments, cement may degrade and lose it beneficial properties such as mechanical integrity and hydraulic conductivity. It is of importance to address durability at different environments and provide solutions to prevent cement degradation with time.

Chemical degradation consists of (CO2 Attack, Sulfate Attack, and H2S Attack).

II.2.3. Cement tests:

II.2.3.1. Compressive Strength Test (43):

The compressive strength of cement was measured by using a hydraulic press, which has a load range from 0 to 88,185 lbf and an accuracy of 220 lbf.

II.2.3.2. Tensile Strength Test (43):

The tensile strength test is also called a Brazilian test (Figure II.4). The cylinder sample height is 2 in. and the diameter of the cylinder sample is also 2 in. The tensile strength can be calculated by using Equation (2.5).

$$\sigma = \frac{2P}{\pi LD} \qquad 2.5$$

Where:

P is load in lbf, L is sample length in ft, and D is sample diameter in ft.

Figure II.4: Brazilian test (43).

II.2.3.3. Hydraulic testing (44):

Hydraulic testing allows verification of the isolation provided by the cement (i.e. no communication path).

A positive pressure test is generally performed at the end of every surface and intermediate cement job. It consists of two steps:

- The casing test should be performed at the end of the cement placement (after bumping the top plug, while the cement is still a fluid) to prevent damage of the cement sheath. Pressure is applied and held to verify the casing integrity,
- The formation integrity test (FIT) or leak-off test (LOT) is performed once the cement has set and after drilling the casing shoe and a few meters of the new formation. The pressure is increased slowly inside the casing and monitored. A pressure drop could indicate a poor cement job and a remedial job (squeeze) may then be required across the casing shoe. If the pressure holds, the hydraulic seal at the casing shoe can be established.

A negative pressure test or inflow test consists of creating a depression inside the casing and to monitor any inflow/pressure variation to ensure the seal is established in both directions. This is only used in specific situations, for example cement plug evaluation, top of liner evaluation, squeeze evaluation.

II.3. Wellhead Systems (14):

A wellhead system is the surface termination of a wellbore and it is composed of spools, valves, and assorted adaptors that provide pressure control of a production well. Wellhead systems incorporate facilities for installing casing hangers, tubing hanger, and Christmas tree. The wellhead systems can be categorized depending on the place where the wellhead is installed as surface wellhead systems and subsea wellhead systems. There are two types of wellheads used for surface applications; spool type and compact type. Other names used for the compact type wellheads are speed head, unitized head, bowl head, multi-bowl head, and unihead. Each of these configurations has their own advantages and challenges in the course of P&A. Table II.1 lists advantages and challenges for each system. As the subject of wellheads is an extensive area, wellhead systems will be reviewed based on the first classification system.

Table II.1: Advantages and limitations of wellhead systems with respect to P&A operations (14).

Wellhead type	Advantages	Disadvantages
Spool type	• The relative simplicity of the suspension and sealing systems	• Requires removal and the re-installation and testing of the BOPs for the removal of each casing head spool. • They have more connections and consequently more risk of leakage
Compact type	• Less height • Fewer potential leak paths	• Lack of tolerance of damage to the hanger sealing areas

As wellhead type is related to the number of connections or components and consequently the risk of leakage, it is important to analyze the wellhead condition. In March 2012, on Elgin installation (approximately 200 km east of Aberdeen, Scotland) located in the North Sea experienced a major incident of uncontrolled release of hydrocarbons to atmosphere. In this incident, reservoir gas from the Chalk formation leaked to the A-annulus to B-annulus, and then to C-annulus. Due to poor sealing capability of wellhead components and connections, the gas leaked to the conductor, D-annulus. As the conductor annulus, D-annulus, is not connected to any barrier for preventing leaks, the gas leaked to the environment uncontrollably, Figure II.5. This incident had no loss of life and well control was achieved by killing the well by pumping kill mud.

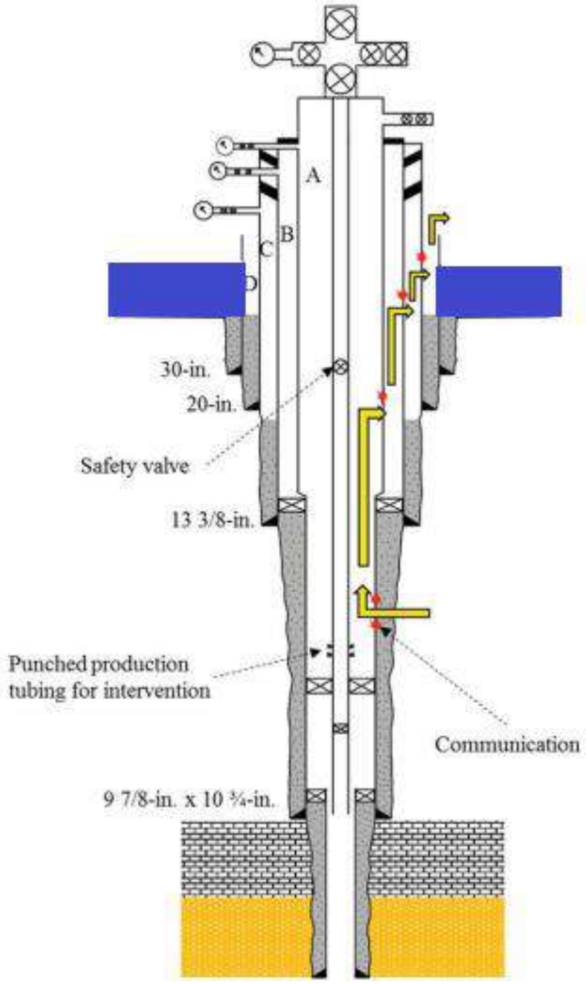


Figure II.5: The schematic of the leak path from Elgin, platform well (45).

II.3.1. Wellhead installations (46):

The first string of pipe to be used in a well is called the conductor pipe. To begin, a large diameter hole is drilled to a specified depth, generally relatively shallow, such as 1 or 200 feet. In most cases, an adaptor flange or a drilling flange is welded to the conductor pipe as a means to connect a diverter system or blowout preventer system.

Upon completion of the surface hole, the surface pipe is run to a specified depth to isolate any freshwater, saltwater, oil or gas zones within that depth range. The surface pipe is run and cemented in place back to the surface. A cement plug is left in the surface pipe, so that a diverter system or a BOP system may be disconnected or nippled down safely.

After the diverter or BOP system has been nippled down, the surface pipe is drained. Then the adapter flange or drilling flange is cut off, then the depth of the slip on socket in the bottom of the casing head housing. If a base plate is used, its height must also be considered.

Casing head housing is prepared for installation. The casing head housing is welded in place on the surface casing. The pieces welded on the inside diameter and the outside diameter, then tested to assure there are no leak paths in the wells. This test checks the wells, but does not test the integrity of the casing head housing. The base plate which is slightly larger than the conductor pipe, may be tack welded to the conductor pipe, When the casing head housing has been successfully welded and tested, the BOP system is installed or nippled up and preparations are made to drill out for the intermediate string of casing. To test the BOP system, the test plug is made up from the drilling string and lowered through the BOP system, until properly located in the casing head bowl. Pressure is applied from above the plug and the BOP system is teste.

Upon completion of the BOP tests, the wear bushing installed on the running tool. The wear bushing is then lowered through the BOP system until located in the casing head bowl. The wear bushing is locked in place, either by lockdown pins in the casing head housing flange or by lockdown pins located in a lockdown flange. The running tool is then removed and the drilling operation can resume.

After the hole has been drilled for the intermediate string, the intermediate string is cemented to a predetermined depth to ensure a good cement bond is obtained between the surface casing and the intermediate casing. A cement plug is left in the intermediate casing, and the casing hanger is installed either through the BOP system or underneath the BOP system.

To begin, the BOP system is nippled down and picked up to a height approximately 3 feet. The casing hanger is then installed. Holes are cut in the casing to allow the drilling fluids to drain out of the casing riser. When the casing has drained, a rough cut is made and the balance of the casing riser is removed. The BOP system is removed. The casing spool with a crossover seal is installed. The BOP system is nippled up and preparation is made to drill out for the production casing string.

To test the BOP system the test plug is made up on the drill string and lowered through the BOP system, until properly located in the casing spool bowl. Pressure is applied from above the plug and the BOP system is tested. Upon completion of the BOP tests, the wear bushing running tool is made up on the drill string and the wear bushing installed on the running tool. The wear bushing is then lowered through the BOP system until located in the casing spool bowl. The wear bushing is locked in place either by lockdown pins and the casing spool flange or by lockdown pins located in a lockdown flange. The running tool is then removed and the drilling operation can resume.

The production casing string is generally run to the total depth of the well and the casing string in which the production packer is installed. When the hole is drilled and the production casing is run and cemented in place, the casing hanger is installed. The casing riser is drained. A rough cut is made and the BOP system removed. The final cut is made to the production casing in preparation for installation of the tubing spool. The tubing spool with a crossover seal is installed in the same manner as the casing spool. After the tubing spool has been installed, the seals and connection are tested and the BOP system is nippled up.

Preparations are now made to run production tubing in the hole. Production tubing is considered any pipe string 4 inches in diameter or less, though sometimes larger sizes of pipe are used. When the plug has been drilled out and a cleanout trip completed, the perforating gun is run in the hole and the casing is perforated or shot. The downhole packer assembly is run and installed in the production casing. A packer is in essence a CO assembly that isolates the reservoir from all strings of pipe, except the production tubing. The production tubing is run with a bottom hole assembly to seal inside the packer. After the tubing is spaced out and proper weight set on the packer, the tubing hanger is installed at the tubing on the rig floor, and then lowered into the bowl of the tubing spool. The BOP system is nippled down and preparations are made to install the production Christmas tree.

Wellhead assembly is shown in the figure II.6.

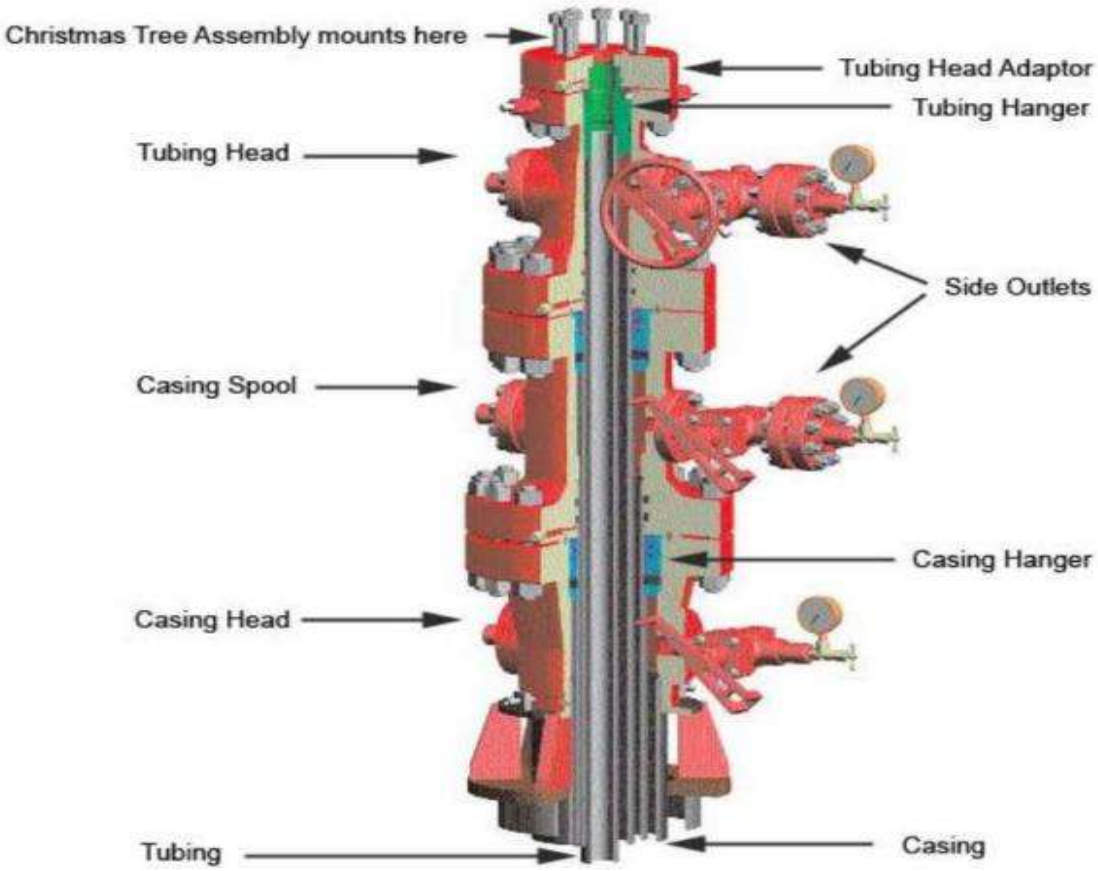


Figure II.6: wellhead assembly (47).

II.3.2. Installing Christmas tree (48):

The main phases are as follows in the order:

- The BOPs are replaced by the Christmas tree,
- The production wellhead is tested,
- The fluids in the well are changed (annular and clearing fluids are pumped in),
- The surface controlled subsurface safety valve is set and tested,
- The well is cleared.

II.3.3. Testing Wellhead and Christmas tree (48):

A series of hydraulic tests is run as described below:

- Test tightness between the tubing hanger and its extended neck at wellhead operating pressure, tightness at the top of the annulus (effect on the cement sheath),
- Test the SCSSV control line and particularly its continuity at the wellhead outlet,
- Overall production wellhead test,

- If the adapter plus Christmas tree was not pre-assembled and tested in the shop, a valve by valve pressure test is performed (pressure test from upstream to downstream).

Christmas tree is shown in the figure II.7

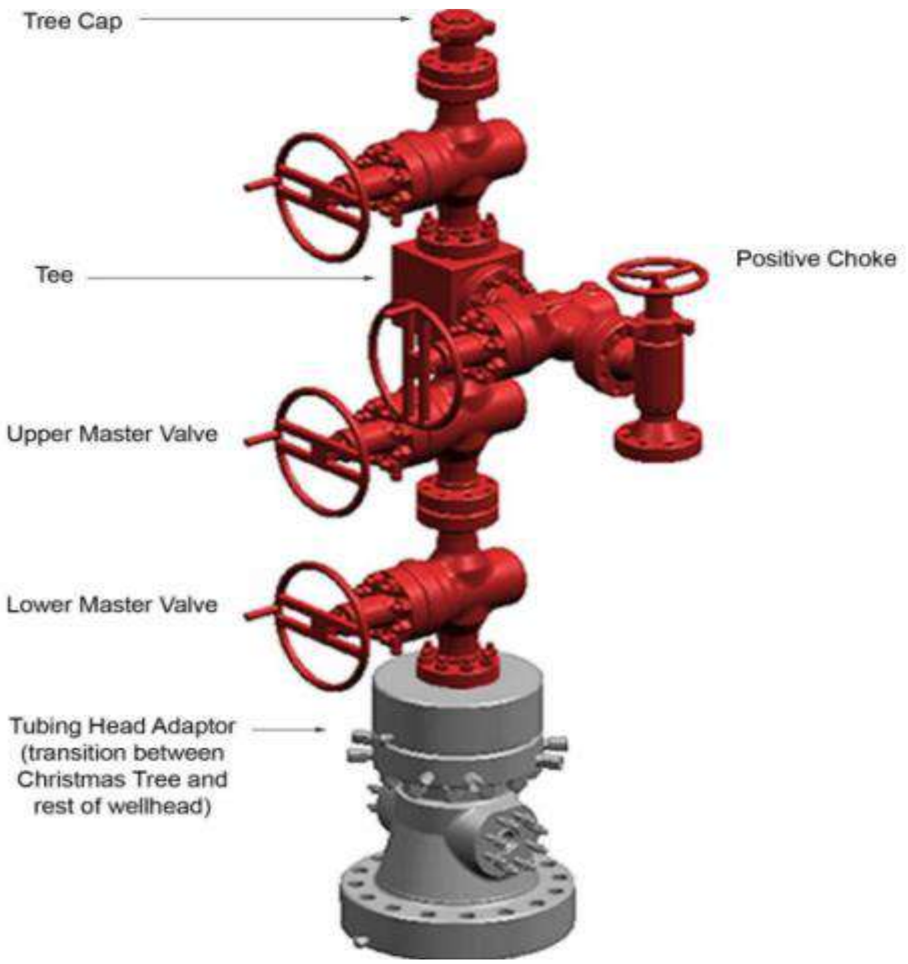


Figure II.7: Christmas tree for a flowing well (47).

II.4. Analyzing of annular pressure:

II.4.1. Different Annulus (49):

The annulus of an oil well is the space between two concentric objects (between casing-casing or casing-tubing). In a completed well, there are normally three annuli or more in some wells in off-shore, this architecture defines the main three annuli as shown in the figure II.8. There are two types of annuli:

- **Annulus type I**:

Is created between the production tubing and production casing in the well, it is confined by wellhead seals from the top and by completion element from the bottom. This annulus is also called annulus ‘A’ based on the position from the well center.

- **Annulus type II**:

Which named as annulus ‘B’, ‘C’? Etc. depending on the annulus position from the well center. In this type, there are no completion elements in the bottom section of the annulus, so it can be found in intermediate or surface casings annuli. The bottom of these annuli is the top of cement (TOC) where the TOC can be under the last shoe or above it is depending on the design plan and purposes (49).

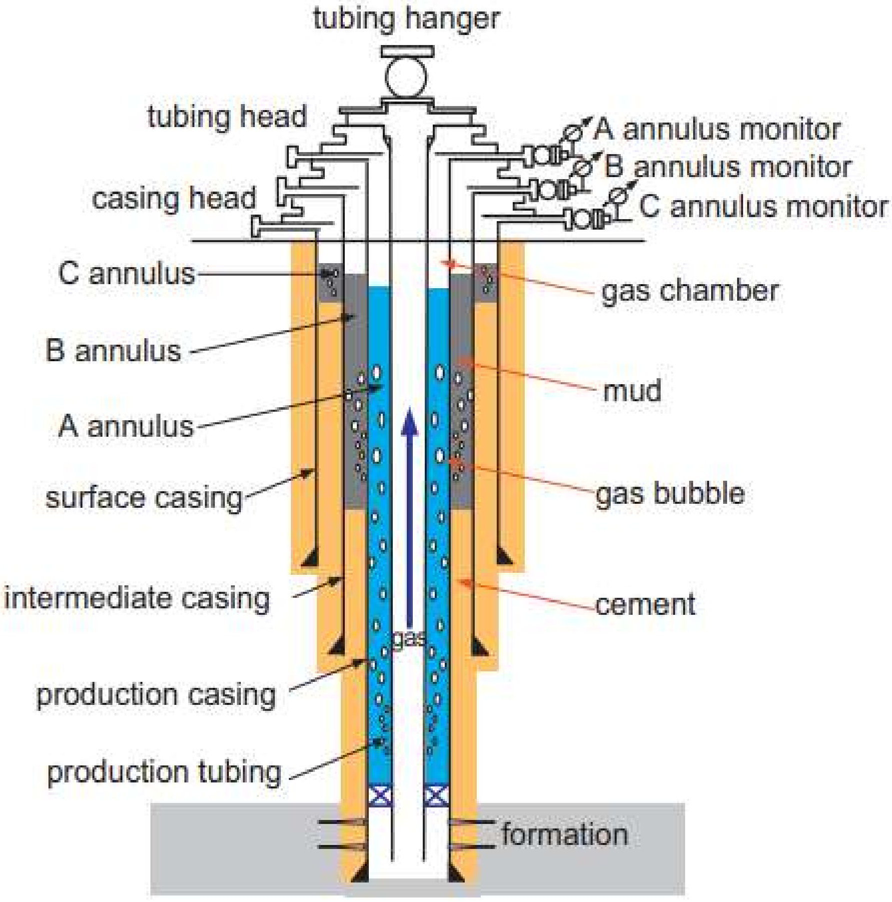


Figure II.8: Different annulus types (49).

II.4.2. Annular pressure (50):

It can easily define it as the pressure that generates by the annular fluid inside the annulus due to volume expansion, fluid migration into the annulus, or operator intentionally performing. Or in a special case can generate accidently due to uncontrolled flow from well.

It will be normal in case of annular pressure less than the permissible limit and abnormal if it exceeds permissible limits.

II.4.3. Annulus integrity (50):

Annulus integrity is the part of well integrity that effected by abnormal annular pressure directly and as a consequence the damage of well integrity, so the most important scenarios that can be applied during well integrity risk analysis threat by annular pressure are based on:

- Maximum wellhead pressure. This type of pressure can pressurize the wellhead, hanger, or cemented casing,
- Maximum differential burst pressure of uncemented casing this pressure put this part of the casing under the risk of the burst. The differential burst pressure of the uncemented part of the casing will increase when both of the annulus pressure of the outer and inner are decreases,
- Maximum differential collapse pressure, this pressure put the packer and production casing/tubing at the risk of failure.

Based on these scenarios the analysis of risk calculation depending on production-related loads and venting of annuli (it can be considered), and the outcome of this analysis can provide the level of risk of annular pressure on the given annulus and its effect on well integrity.

II.4.4. Sustained casing/annular pressure SCP or SAP (50):

The SCP is recognized from other types by the ability to rising again after bleeding because it depends on the pressure difference between the annulus and feeding source (formation or leakage tubing) and permeability or severity of channeled cement. The annular sealing may fail due to cementation operation errors such as incorrect mud displacement, gas leaks through cement liquid-solid transition, and cracking of cement sheath during well age. The pressure measure in all of the casing strings after the well completion, it must be zero, when there is a steady-state condition of well flowing, and there is a little fluid volume generated the effect of thermal expansion it should be vent through the wellhead to equalize the annulus casing pressure to the normal atmospheric pressure.

II.4.5. Annulus pressure causes (51):

In addition to thermal effects, annular pressure change may be driven by:

- Loss of cement integrity, formation integrity, packer / seal integrity,
- Downhole gas lift operations for production optimization,
- Pressure leakage through the completion hardware such as the production packers,
- Pressure leakage through the production tubing or casing string,
- Leakage through the crossover valves in the subsea tree,
- Leakage from an HP or LP hydraulic line,
- Leakage from a downhole chemical injection line, leaking control line,
- Wellhead or tubing hanger leakage,
- Ballooning.

II.4.6. Annulus pressure evaluation (52):

The probability of failures and loss of containment due to SCP are closely related to the resulting excessive annulus pressures. Assessing the potential annulus pressures caused by SCP is therefore a key part of the evaluation. The annulus pressure can be evaluated through controlled pressure build up to investigate the potential maximum stabilized pressure. During such assessments the maximum allowable annulus surface pressure for this activity should be clearly defined and regardless of stabilization the pressure build up should be discontinued if this limit is approached.

II.4.7. Annulus pressure monitoring procedure (53):

- Monitoring and trending of pressures,
- Recording of fluid types / volumes added / removed,
- Establish frequency and type of monitoring,
- Periodic testing of well barriers,
- Operational changes to the well or other wells / surroundings,
- Calibration and function checks of the monitoring equipment,
- Periodic review of well stock.

II.5. Conclusion:

In order to maintain safe wellbore integrity over a well's life cycle (drilling through to post abandonment), chemical, mechanical and physical factors impacting integrity need to be thoroughly assessed and periodically monitored. Chemical impact assessment such as cement property evaluation, corrosion in cement is required to minimize the degradation in cement and casing properties across the possible spectrum of wellbore environments. Awareness of acid gas concentrations is essential as these tend to aggressively degrade cement, requiring more rigorous monitoring of the cement's condition and characteristic properties over time to maintain safe operations. Casing is susceptible to corrosive environments, which again are more significant in the presence of acid gasses and also require careful evaluation and monitoring of casing conditions over time in order to verify that it continues to provide an integrity barrier. Also wellhead and Christmas tree equipment are exposed to different factors can lead to their functioning failure which impact the integrity of the well for this reason wellhead assembly and Christmas tree should be tested and verified through well's life cycle. Annulus pressure is another factor with a very important impact on the well integrity safety therefore it should be well monitored.

CHAPTER THREE

HOW TO EVALUATE CEMENT BOND

III.1. Introduction:

All of us can readily recognize construction cement for what it is because we see it every day and it looks how it is supposed to look. Even a poor grade of construction cement is recognizable as cement to the naked eye. In our industry, cement is placed in the casing/open hole annulus for two primary purposes: to isolate producible formation horizons and to support the casing. However, we do not have the luxury of looking at the cement with the naked eye to determine its quantity and/or quality after placement. We are forced to rely on the results of measurements from a variety of electronic downhole tools to define the quality and quantity of cement placed around the casing during the primary cement placement.

Cement bond logs (CBL) and variable density log (VDL) are one of the vital logging techniques used to evaluate cement casing-formation bonds before the well testing or execution of the production operation in the well. These logs are also crucial during the workover operation to maintain the integrity of the well. The logging techniques provide a clear view of the quality of cement bonds with casing and formation.

The major problem associated with interpretation of the results of these measurements lies within one's definition of "good" or "poor" cement. All the cement-evaluation tools available today, as well as the service companies that design and run them, are caught in the vicious cycle of trying to define good or bad cement in the oil well/gas well annular space.

III.2. Definition of CBL:

The Cement Bond Logging tools have become the standard method of evaluating cement jobs. They indicate how good the cement bond is. A cement bond log (CBL) documents an evaluation of the integrity of cement job performed on an oil well. It is basically a sonic tool which is run on wireline. Similar to a ringing bell, when no cement is bonded to the casing, pipe is free to vibrate (loud sound). When the casing is bonded to hard cement, casing vibrations are attenuated proportionally to bonded surface (54).

III.3. Sonde centering:

Proper centralization of the logging sonde in the casing is more critical with short-spaced tools. For example, centering a 3-ft-spaced tool by $\frac{1}{4}$ in. causes an amplitude reduction up to 50 percent of the value otherwise recorded with a perfectly centered tool, thereby giving a false indication of bond quality. Thus, properly centered tools are of utmost importance in large casings and in directional holes. Also, tools should not be run too fast since at high speeds, such as 4,000ft/hr, the sonde maybe jerked off center (55).

III.4. Description of the conventional bond-logging tool:

Figure III.1 shows a schematic diagram of a representative bond-log tool, together with a cross section of a cased and cemented well. The tool has an acoustic transmitter that is usually made of a piezoelectric ceramic. There are two receivers, also of piezoelectric ceramics, in most tools. Some designs incorporate a single receiver. In the former case, the two receivers are generally located 3 ft [0.9 m] and 5 ft [1.5 m] from the transmitter. In the latter, the single receiver is 4 ft [1.2 m] from the transmitter. Some hostile-environment tools use magneto restrictive transducers rather than those made of ceramics. This requires different pressure and temperature corrections. Not shown in the figure, but required adjuncts for the tool, are a sufficient number of centralizers to ensure that the transmitter/receiver section of the tool remains centered in the pipe (41).

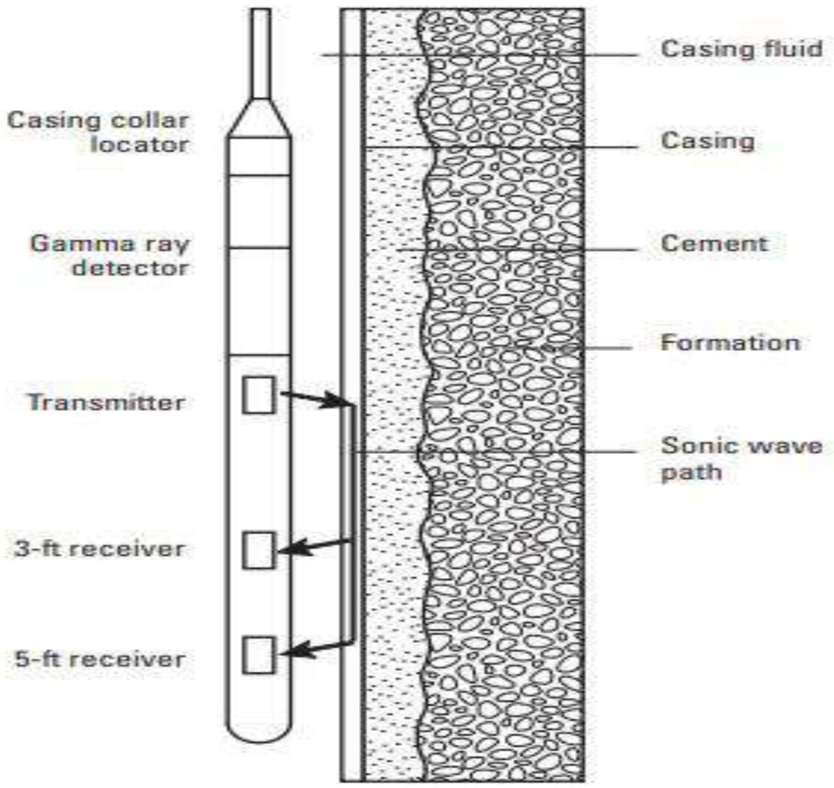


Figure III.1: CBL-VDL tool configuration (41).

III.5. How CBL works (56):

The transmitter repeatedly emits short bursts of acoustical energy. The duration of each burst is about 50 p, and the repetition rate is between 10 to 60 Hz, depending upon the particular tool design (and on the setting made by the logging engineer, in some cases). The frequency content of each burst is centered at about 20 kHz for larger diameter tools (larger than 3 in. or 8 cm) and about 30 kHz for smaller diameter tools (less than 2 in. or 5 cm). One company offers a tool with a center frequency of 12 kHz. In the time interval between transmitter bursts, the receiver picks up the signal and makes the bond log measurements. Most of the signal of interest arrives at the receiver within one to two milliseconds after the transmitted burst.

The transmitter burst creates an approximately spherical wave front expanding away from the tool in all directions. As the wave front strikes the inside wall of the casing, it is refracted according to Snell's law. There is one particular direction of travel of the wave front that will result in refraction straight down the pipe. This is the "critical angle." It is about 16.5" with fresh water in the hole. The part of the wave front which is refracted straight down the pipe ultimately determines the "amplitude" and "transit-time" measurements which appear on the log. Some parts of the original wave front travel directly through the mud, and some parts are refracted into the annulus and formation. Part of the latter ultimately arrives at the receiver as a "formation signal," and the former shows up as "mud waves."
Figure III.2, is a schematic representation of these various "paths" which the original burst can follow and still arrive at the receiver. The waveforms in the figure are meant to convey the relative times of arrival of the acoustic energy which has traveled along the various paths. The wave which is refracted directly down the casing wall usually arrives first because of the high velocity of sound in steel combined with the relatively short distance. A relatively low sound speed in fluids results in the mud wave arriving very late in spite of having the shortest distance to travel. The arrival time of the formation wave, both shear and compressional, is highly variable). The signal from the receiver will be a mixture, or composite, of waves from all these paths. The interpretation of the actual bond log measurement (as opposed to a picture of the entire composite wave) depends upon the casing wave arriving before anything else. Since they are not used in bond log interpretation, the Stoneley and Rayleigh waves are not discussed here. If the annulus contains a fluid, so little energy arrives at the formation that the received signal consists almost exclusively of the casing signal and the mud waves.

The so-called casing wave is the portion of the original acoustic burst which propagates directly down the casing wall. It loses energy into the annulus and borehole as it propagates, because of the shear coupling with the adjacent materials. The greater the shear coupling, the greater the energy “lost” into the adjacent materials. The loss to the borehole is low and constant: thus, the loss to the annulus is the variable. The rate of this loss is reflected in the “amplitude” or “attenuation” appearing on the log. It should be expected that there will be little attenuation of the casing signal if there is a fluid in the annulus. In fact, all fluids would be expected to “1ook”alike because there is no shear coupling for any fluid. This is also the reason why even a microscopic gap of a few thousandths of an inch between the pipe and a cement sheath, referred to as a “micro annulus,” has a strong effect on the signal.

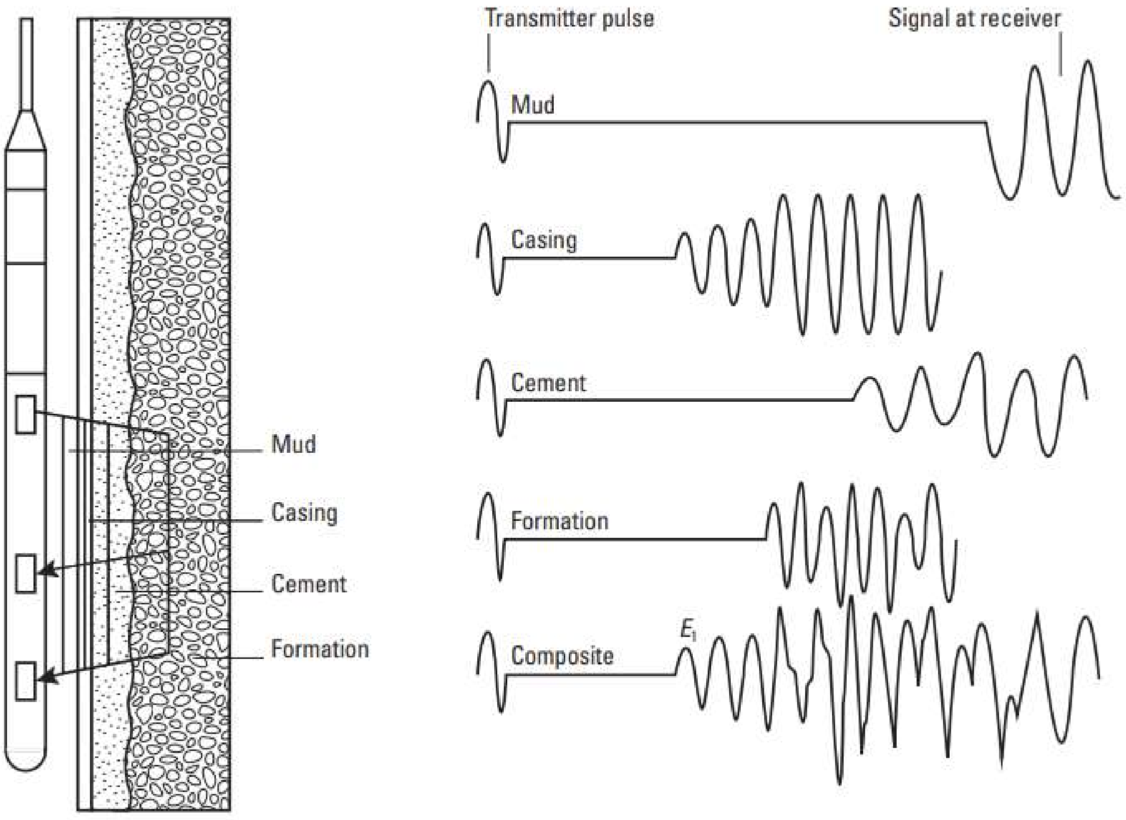


Figure III.2: Sonic wave paths (41).

III.6. Interpretation of CBL:

III.6.1. CBL-VDL-Qualitative Interpretation:

The analysis of the full wave display gives only qualitative information about the cement job. If the cement is well bonded to the casing, most of the sonic energy will leave the casing and pass into the cement-casing waves will have an extremely low amplitude. If the cement is well bonded to the formation, the energy will go through the cement into the formation. The sonic waves will then propagate (compressional and shear) and attenuate through the formation. Since formations are never perfectly homogeneous, their acoustic properties change with depth. Wavy patterns on the received waveforms are the perfect illustration of this, a qualitative indication of good acoustic coupling between cement and formation, and also between casing and cement (41).

III.6.2. CBL Quantitative Interpretation (56):

Experiments proved the attenuation rate to be linearly related to the percentage of the circumference of the casing bonded by the cement, from which the concept of Bond Index (BI) was derived .Its validity, was later extended to the percentage of cemented area, regardless of the shape and fluid of the non-cemented area. The Bond Index is the only quantitative information which can be derived from a CBL. Its calculation requires the knowledge of the log response in the well cemented section, which is used as a reference for the computation of a (100% cemented).

$$BI\ (x) = \frac{A\ (x)}{A\ (\ 100\%\ \text{cemented})} \qquad 3.1$$

Where:

A is the CBL attenuation rate. The Bond Index equation can also be solved graphically using semi log paper once the 100% cemented pipe amplitude is known.

III.6.3. Basic Cement Bond Log Interpretation (57):

Cement bond log interpretation is done following these steps (Figure III.3):

- Calculate Min and Max amplitudes,
- Perform "CBL Triage",
- Determine Formation Arrivals,

  Prominent formation arrivals indicate channeling as opposed to weak cement or micro-annulus,
- Micro-annulus or Weak Cement.

Micro-annulus is caused by two factors:

- Aggressive cementing program (low retardants, high pumping rates),
- Low-grade casing,
- CBL/VDL alone cannot distinguish between micro-annulus or low compressive strength cement.

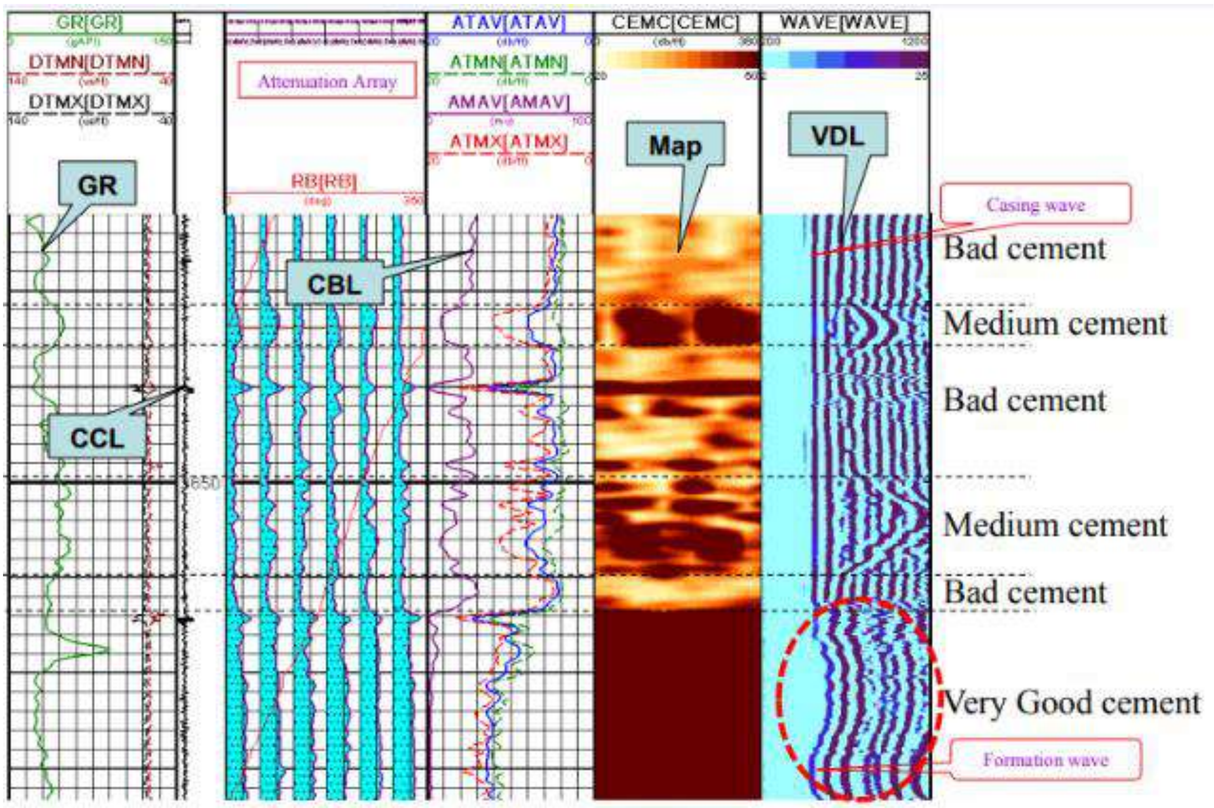


Figure III.3: Cement bond log interpretation (58).

III.7. Cement bond log interpretation models:

III.7.1. Good cement (59):

When the cement is well bonded, the log shows (figure III.4):

- low Amplitude,
- Transit time is different from that measured in free casing,

If there a jump up cycle, it is visible on the transit time and CL indicates very low amplitude.

In all cases, the VDL shows very weak or non-existent casing waves and very clear formation waves whose variations correspond to those seen on the sonic recorded in open hole.

VDL formation signals are strong.

Good cement. No need for squeeze.

III.7.2. No cement (59):

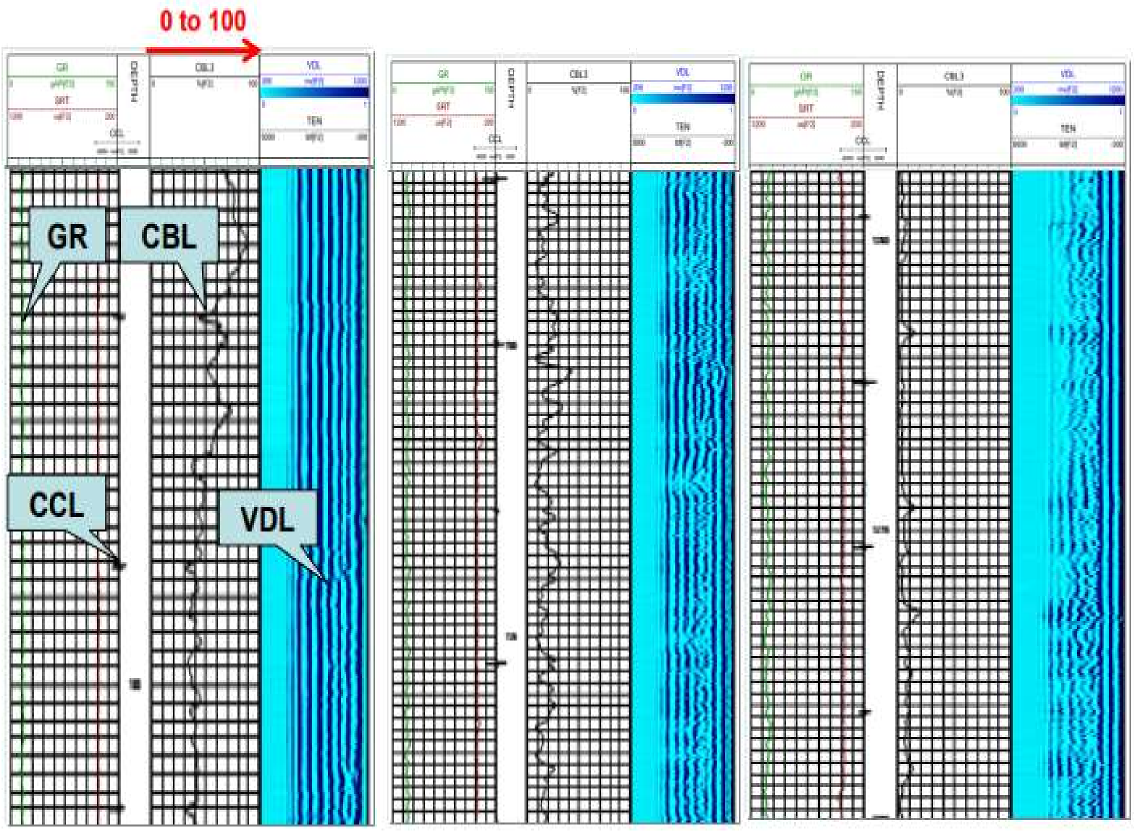
When the cement is not bonded, the log shows (figure III.4):

- High Amplitude (corresponding to the one expected according to the diameter of the casing),
- Transit time approximately equal to that calculated from the mud and casing data,
- VDL straight. No formation signals. "V" type Chevron patterns are seen at collars,
- Very clear, straight and parallel casing waves on the VDL,
- Net casing threads for all logs, Squeeze cement needed.

III.7.3. Partial cement (59):

When the cement is partially bonded, the log shows (figure III.4):

- “Amplitude” is low and moderate,
- “VDL” can shows both wiggly formation signals and straight casing signals,
- Squeeze can be necessary if the channel is long enough.



Poor cement medium cement good cement

Figure III.4: Different cement bond log quality (58).

III.7.4. Microannulus (60):

A micro gap between cement and casing is appearing in figure III.5:

- "Amplitude" is moderate,
- "VDL" can shows both wiggly formation signals and straight casing signals,
- Well bonded cement-casing, no bond for cement-formation,

The casing waves are vert attenuated (amplitude on the cbl and slip or jump up cycle on the T.T) the formation waves do not appear and only the mud waves arrive after the casing waves.

The acoustic coupling is done, part of the energy passes through the casing, the CBL is not at its maximum. As part of the energy passes through the formation we notice formation waves on the VDL.

Only a second control before pressurizing the casing will show if the coupling is improving. Reduction of the CBL amplitude ad clear attenuation of the casing waves on the VDL, thus confirming the presence of the micro annulus.

- fast formations,

In the case of compact or very low porosity formations whose ΔT is lower than the ΔT of the casing steel (57 μs/feet), the formation wave arrives first, the CBL becomes unusable.

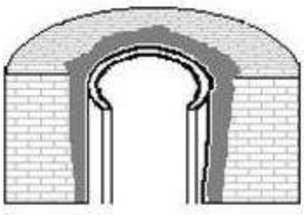
On the VDL, the casing wave is replaced by a faster formation wave.

- Slow speed and high attenuation formations.

In the case of slow formations (of 77 to 125 μs/feet) the acoustic energy will be more transmitted by the cement than the formation. Formation waves appear very weak, even non-existent. The arrival of the mud waves can even be visible before the formation wave. It is the of the surface formations

In case of doubt, repeat the log under 1000psi pressure to the well. The gap will be closed and log will change to "Good Cement"

No need for squeeze.



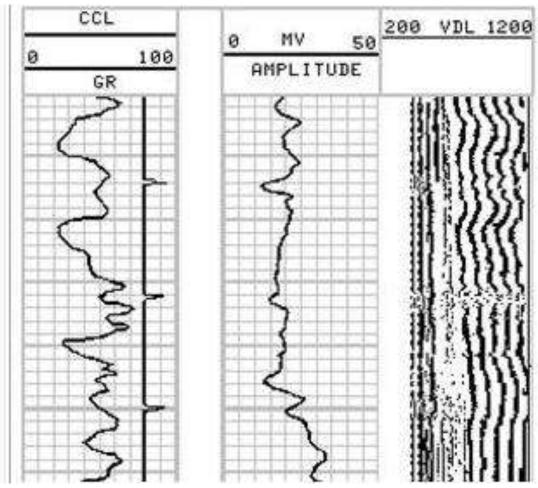


Figure III.5: Microannulus interpretation (59).

III.7.5. Cement without bond to formation (61):

The cement is not bonded to formation as shown in figure III.6:

- “Amplitude” low,
- “VDL” doesn't show casing and formation signals. Thin mud signals are visible · Squeeze needed.

Keep in mind that gas in formation can give the same model.

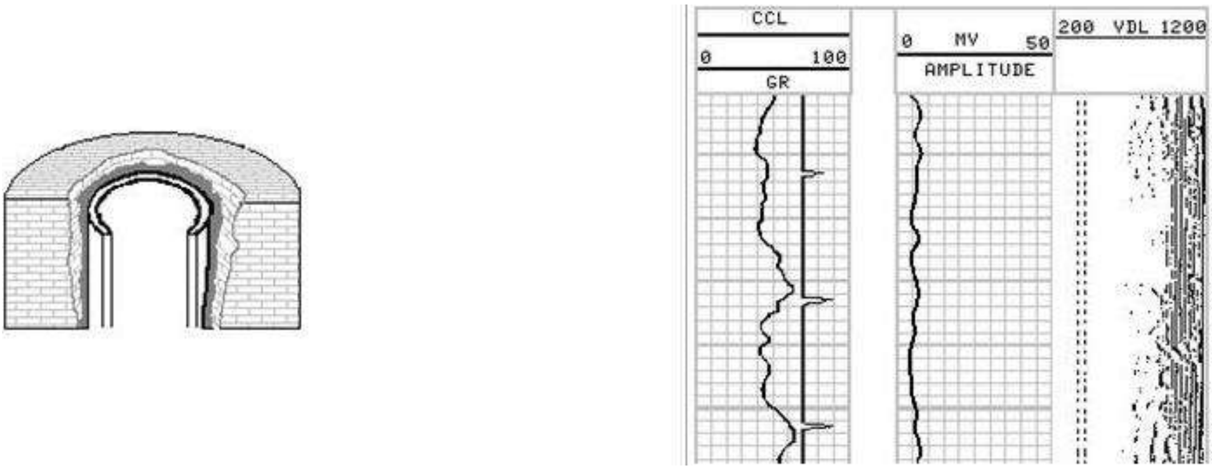


Figure III.6: Cement without bond to formation (59).

III.7.6. Cement bond in hard formation (61):

Cement bond in hard formation is shown in figure III.7:

- Amplitude changes between low and high,
- Formation signals cover casing signals,
- No need for cement.

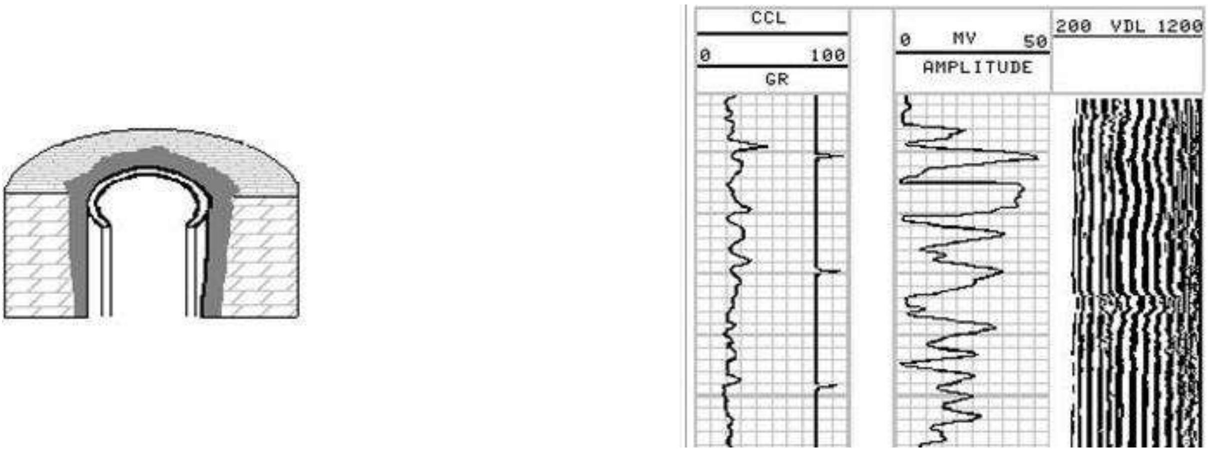


Figure III.7: Cement bond in hard formation (59).

III.8. Log Quality (62):

Many factors affect the response of bond-log tools. These factors can be broken into three categories: those that are controllable during running the tool, those that are controllable during the cementing operation, and those that are constraints imposed by the wellbore or formation.

III.8.1. Microannulus:

A microannulus is defined as a very small (approximately 0.01 to 0.1 mm) annular gap between the casing and the cement sheath. A microannulus can result in a misinterpretation of the CBL/VDL. All cement logs are sensitive to microannuli to varying degrees. Microannuli are caused by temperature, mud cake deposits, pipe coatings, and constraining forces. Common procedure is to place approximately 1,000 to 1,500 psi pressure on the casing to close the gap (62).

III.8.2. Eccentralization:

It is difficult to predict the exact bond status behind casing if it is eccentralized. Most likely there is no cement at the low side where the distance between casing and formation face is small (62).

III.8.3. Logging-Tool Centralization:

It is mandatory that the CBL/ VDL tools are well centralized. the CBL/VDL part of the tools is affected negatively. Tool centralization can be checked in the log presentations. Combining eccentralized tools such as a gyroscope may affect CBL-tool centralization negatively. Centralizers attached to the tool must allow for smooth, even tool movement. As the number of centralizers increases, the risk of jerky, erratic tool movement increases (62).

III.8.4. Fast Formations:

Formations with very high velocity and short transit time are called “fast formations.” Acoustic signals from anhydrites, low porosity limestone, and dolomites often reach the receiver ahead of the pipe signal. Signal amplitude is high but not as high as free pipe. Fast formations affect the CBL/VDLs. If there are fast-formation signals present, it is assumed that the CBL/VDL cannot be interpreted, though the arrival of the fast-formation signals suggests that the cement to-formation bond is present (62).

III.8.5. Lightweight Cement:

Cement evaluation relies on a contrast in the acoustic properties of the cement and liquid. The higher the contrast between liquid and hardened cement, the easier the log is to interpret. The acoustic properties of set lightweight cement are close to those of cement slurry, making it difficult to distinguish the two. Lightweight slurries use hollow ceramic microspheres, nitrogen, and other low-specific-gravity materials to achieve a light density while providing good compressive strength. These cements commonly are used in areas of weak formation (62).

III.8.6. Cement Setting Time:

An important consideration in CBL interpretation is the length of time to wait for cement slurry solidification before running the bond log. If the bond log is run before the cement is fully set, a pessimistic interpretation will result, followed by an unnecessary squeeze operation. If the log is run well after the cement is set, an expensive rig sits idle unnecessarily. The hardening time of cement slurries depends on their type and formulation, the downhole temperature profile and pressure conditions, and the degree of drilling-mud contamination (62).

III.9. Consequences of poor cement quality (63):

Poor cementing quality can lead to the following issues:

- Mixing of the produced effluent with unwanted fluids,
- Migration of fluids to the surface through poorly cemented areas,
- Casing corrosion,
- Casing collapse,
- Cross flow.

Figure III.8 shows leakages due to poor cement quality.

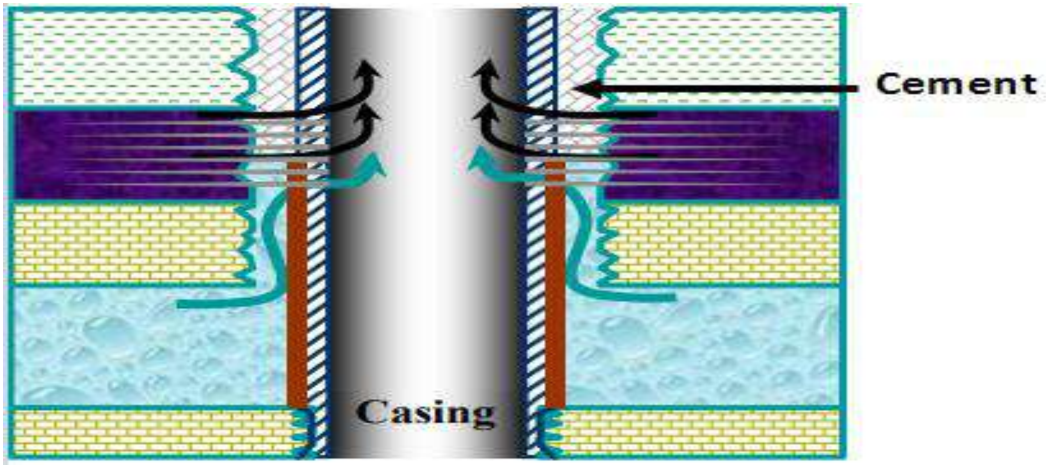


Figure III.8: Poor quality cement consequences (63).

III.10. Conclusions:

Cement Bond Logs and Cement Evaluation Logs play a very important role in hydrocarbon exploitation and production. In spite of the limitations and uncertainties in interpreting these logs, they should be recorded in oil and gas wells for proper completion purposes. Evaluation of cement bond logs should not be undertaken on its own. All available information, including drilling and cementing data, should be taken into consideration when evaluating cement bond logs, as high impact decisions are based on the results of these interpretations. All relevant and interested parties, such as surface team members and drilling personnel should be involved in the decision making process, should there be a possibility of performing a remedial cementing job, such as squeeze cementing. All possible causes of the apparently poor quality of the cement bond should be thoroughly investigated before a decision for remedial cementing job is taken, as they can be very expensive to implement and the chance of success could also be low. However, if it is proven beyond a reasonable doubt that the cement bond is indeed poor, all parties concerned should be willing to take the necessary decision to perform a remedial cementing job.

CHAPTER FOUR

CASE STUDY

IV.1. Introduction:

Well integrity refers to maintaining full control of fluids within a well at all times, in order to prevent unintended fluid movement or loss of containment to the environment. Well integrity policy defines commitments and obligations to safeguard health, safety, environment, assets and reputation. The well integrity failure can lead to major accidents causing important financial, equipment, production losses.

We took "Well A" as our well-case study. Where a major gas leak occurred on January 2, 2020, on the "Well A" gas injector well located in the HASSI MESSAOUD field, due to failure of well integrity. The objective of this chapter is:

- Investigate and analyze the circumstances leading to this accident,
- Identify this accident direct and underlying causes,
- Conclusion and set recommendations to avoid any recurrence on the HASSI MESSAOUD field wells.

IV.2. Summary description of the HASSI MESSAOUD field:

The HASSI MESSAOUD field is located about 800 km south-east of ALGIERS and 80 km from the capital of the wilaya of OUARGLA. It is the largest oil deposit in ALGERIA. The city of HASSI MESSAOUD is located inside the exploitation perimeter of the field (Figure IV.1).

The HASSI MESSAOUD deposit is subdivided into two (02) exploitation perimeters: central zones, complex zones &North Upside. It is operated by the HASSI MESSAOUD Regional Direction of the Production Division. It went into production in 1958 with an initial reservoir pressure of 482 kg/cm² and an average GOR of 180 m3 /m3. Cumulative production at the end of 2019 is 1,344.308 million m3.

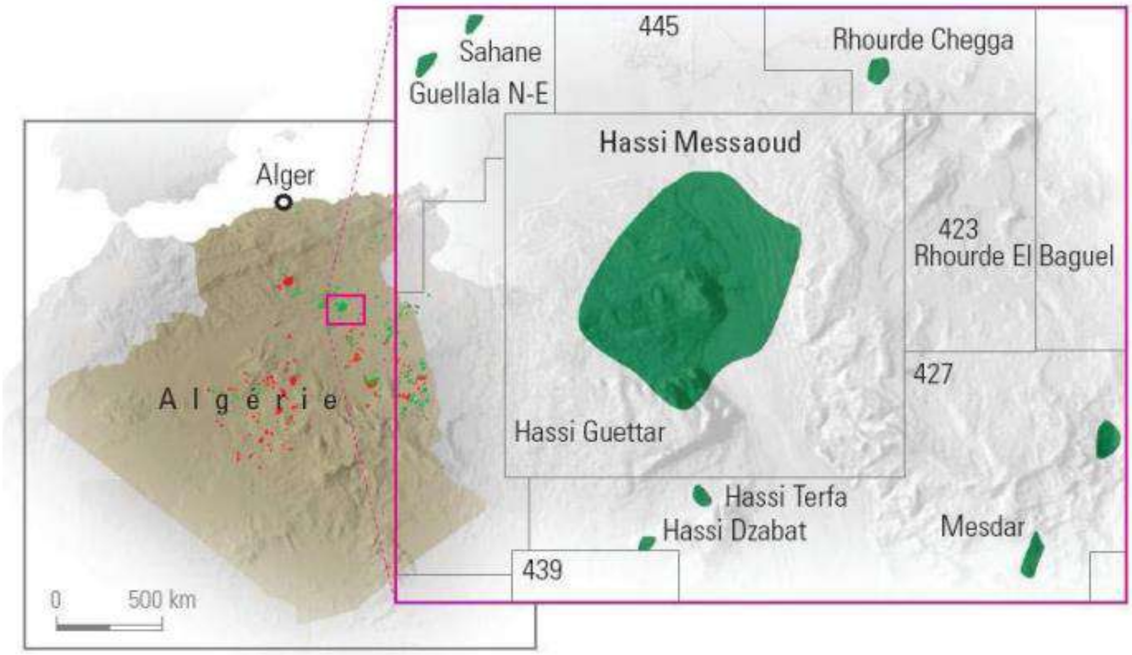


Figure IV.1: Geographical location of the HASSI MESSAOUD field.

The HASSI MESSAOUD field is subdivided into 25 production zones (Figure IV.2) on the basis of the average behavior of the reservoir pressures. Each production zone is defined as a set of wells that communicate with each other, with little or no connection with wells in neighboring zones. Gas injection began in 1964 in Zone 13 South and water injection in 1968 in Zone 17.

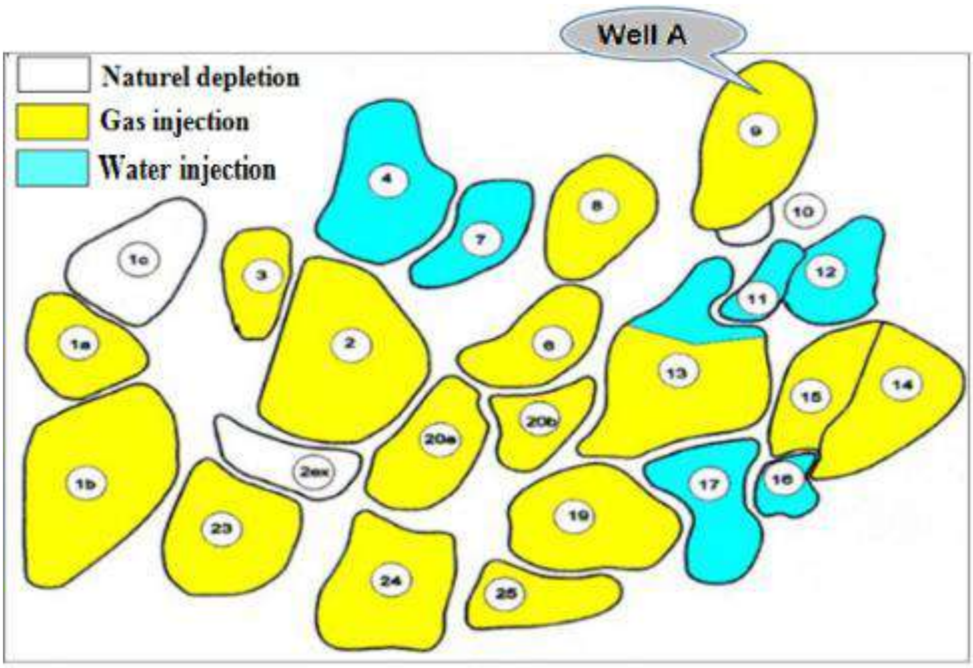


Figure IV.2: Subdivision of the HASSI MESSAOUD field into 25 production zones.

Area 9 is located in the north-east of the HASSI MESSAOUD field, in the central zone perimeter. It was put into production in October 1959 by the "Well A" producing well. The initial reservoir pressure was about 482 kg/cm².

Gas injection began in this area in July 1965 with the conversion of the well B. The "well A" well was converted back to gas injection in 2001

From the start of production in Zone 9 in October 1959 to 1979, the reservoir pressure dropped from 480 kg/cm² to an average of 260 kg/cm². From that date on, the reservoir pressure was maintained by gas injection. To maintain a good miscibility at the level of the gas injection zones at HASSI MESSAOUD, a pressure level of 250 to 260 kg/cm² is required.

The graph in Figure IV.3 shows the evolution of the well pressure in zone 9 as a function of time.

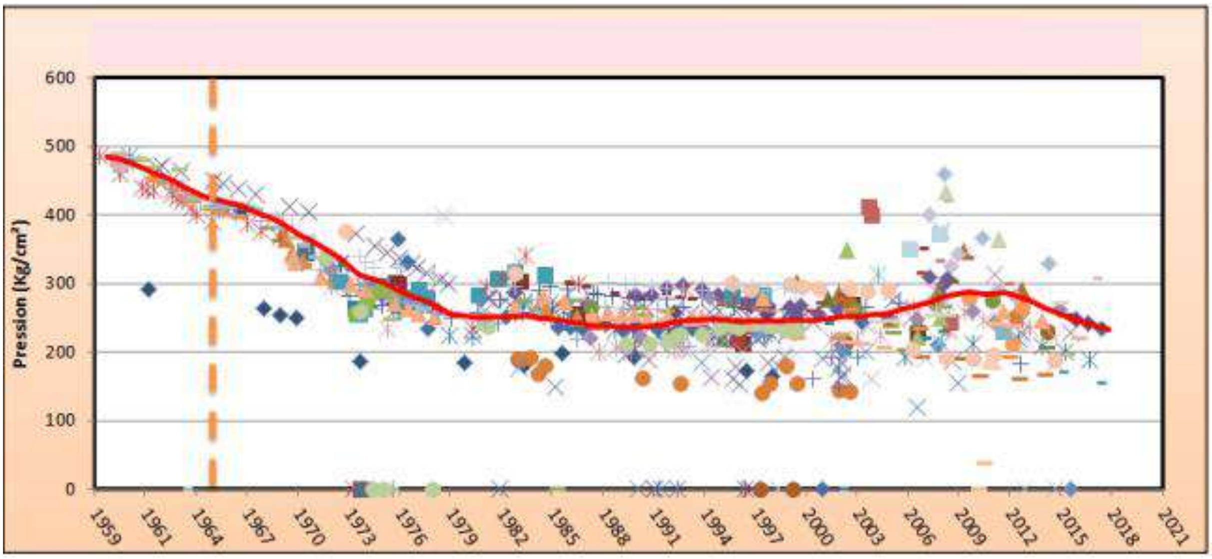


Figure IV.3: Evolution of pressure on producing wells in zone 9.

IV.3. Presentation of “well A”:

IV.3.1. General Information:

Well A is located in zone 09 north of the HASSI MESSAOUD field, about 25 km from the town of HASSI MESSAOUD, 8 km from the agricultural village of HASSI EL BAKRA and 23 km from the IRARA base (Figure IV.4).

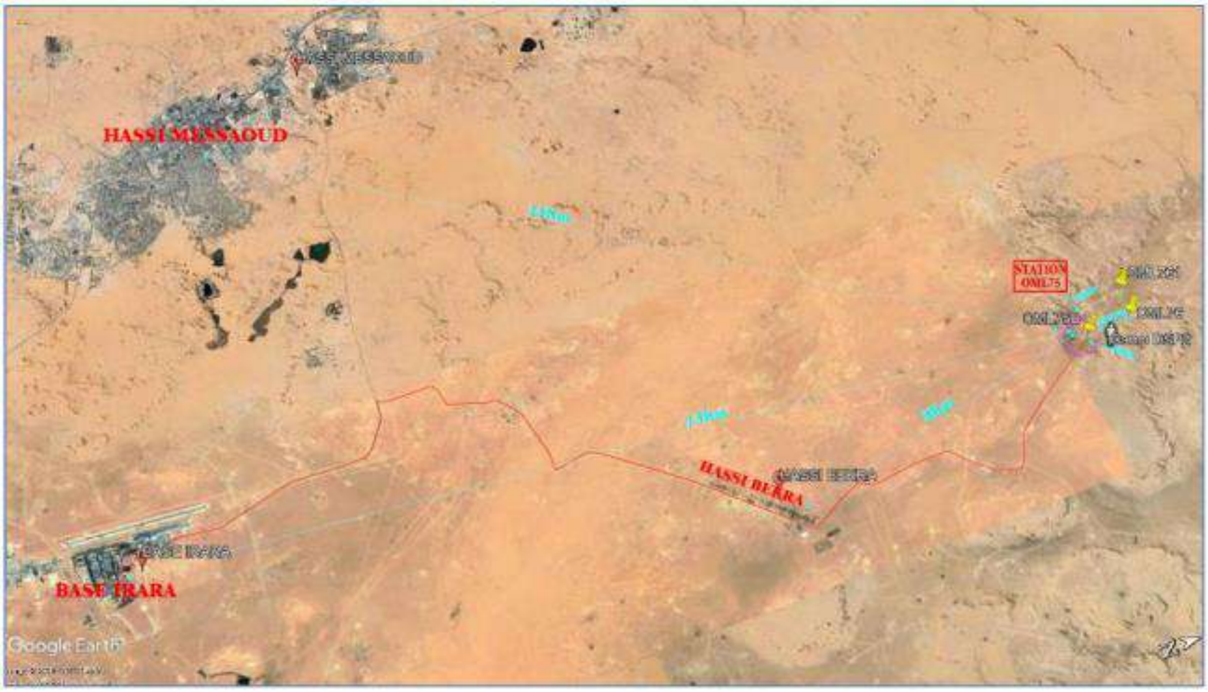


Figure IV.4: Location of the well A in the field.

This well was drilled in 1959 as oil producing well in the Cambrian, replacing the well C abandoned during drilling for technical reasons. It was converted into a gas injector in 2001 to maintain the reservoir pressure and to extract all the oil.

The cumulative oil production from this well from 1959 to 2001 is 4.28 million Stdm³. The cumulative volume of gas injected in this well, from 2001 to the end of 2019, is 1.626 billion Stdm³ with an average injection rate in 2019 of 300,000 Stdm³/day and an average injection pressure of 250 bars.

The gas supply to the well A is provided by a service network coming from the Z-CINA compressor station, through the RNE manifold and an injection skid located near the well.

The well is connected to the telemetry system (Figure IV.5) through which the parameters (pressure and temperature, network pressure, annular pressures, injection rate) are monitored remotely and in real time at the control room located at IRARA.

Telemetry records of this well in the day 02 January 2020 are shown in the (Appendix A and Appendix B).

Figure IV.5: Telemetry recording on December 2019.

IV.3.2. History of well A:

The well A was drilled to replace the "well C", which was abandoned during drilling at depth of 510m due to total mud loss (see Appendix C).

Notes of well C:

- Stuck of the 13" ⅜ column during the descent into the Mio-Pliocene.
- Succession of total losses in the Carbonate Senonian.
- Abandoned hole at 510 m in phase 12" ¼.

IV.3.3. Drilling of well "Well A:

Drilling of the well A began on January 16, 1959. Drilling operations were conducted as follows:

- Drilling in 24" to 256 m, without any particular difficulties,

- Drilling in 12" ¼ to 2480 m, with no particular difficulties and mud loss reported at 275 m,
- Drilling in 8 ½", to 3364 m, a total loss of mud happened in the Triassic, from 3335 m to 3340 m. Plugging with cement plugs,
- Drilling and coring in 6" to 3489 m. No particular problems were reported.
- Completion of the well:
    - Reservoir left in Open Hole,
    - Completion with 4" ½ LTC tubing, anchored in 7" casing with 3" ½ NU under packer extension.

The schematic illustration is shown in (Appendix D).

The evaluation of the cementing of the "Well A" well shows the following:

- Casing 18" ⅝ : no cementing evaluation log,
- Casing 9" ⅝ : the cementing control was carried out with a thermometry log, It indicates a cement top at 730 m located in the right of the Senonian Saliferous,
- Casing 7": the cementing control was carried out with a thermometry log, it indicates the presence of cement over a height of 45 m only from shoe 7", i.e. a cement top at 3315 m. The rest of the column is not cemented,
- A CBL cementing log during a workover operation, confirms good cementing on 12 m only above the 7" shoe and poor cementing on the rest of the column,
- On the drilling and cement job evaluation phase we noticed:
- Missing conductor casing in well A,
- Change in the drilling program on Well A, as compared to the Implementation Report,
- Cementing of the 7" casing in one (01) stage instead of two (02) stages, as planned in the initial drilling program,

Total loss during cementing. Only 12 m above the shoe were well cemented. All the rest is very bad (free pipe).

- Absence in the well A file of some important information such as steel grades and nominal weight for casings.

The detailed drilling program is shown in the (Appendix E).

IV.3.4. Workover operations on well A:

Since the production began on 1959, three (3) workover operations were realized on the well A. There is nothing to report in the first and the second workover operations.

The 3rd workover was carried out after the LD2 communication through the 7" case was detected.

After this operation we noticed:

- Annular space test not performed,
- LD2 communication through the 7" case not located,
- Cementing the 4 ½" tubing to the surface,
- Quality of cementing of 4" ½ tubing: good overall, from Packer 4" ½ from 3345m to 1998m. Poor from this elevation to the surface. Good cementing opposite LD2.

Other Operations on Well A realized and we noticed the following:

- No seat in the 4" ½ tubing for the installation of a bottom safety valve,
- Annular test not performed,
- The type of thread of the tubing is not adequate (LTC instead of VAM).

Workover and others operations are detailed in (Appendix F).

The well A, which began production in October 1959, has accumulated production of 4.28 million m^3. The evolution of the production of this well is shown in Figure 15/appendix.

Notes:

- The well was shut-in in April 1996 following a reduced oil flow to 0.7 m^3 /h and a gas breakthrough,
- For reservoir needs in Zone 9 (pressure maintenance and miscibility), it was decided in 2001 to convert the "well A" well into a gas injector.

The well A had no apparent problems or incidents during the entire injection period, until the occurrence of the accident on January 2, 2020.

IV.4. Cause analysis:

Gas flowing through the 18" ⅝ casing to the surface at the injection pressure of 237 bars indicates that all mechanical barriers providing well integrity have failed in the annulus.

The analysis of the causes of the accident, carried out by the "barrier analysis" method (Figure IV.6), consists of determining the direct and indirect causes that led to the failure of these barriers. This analysis gives the following:

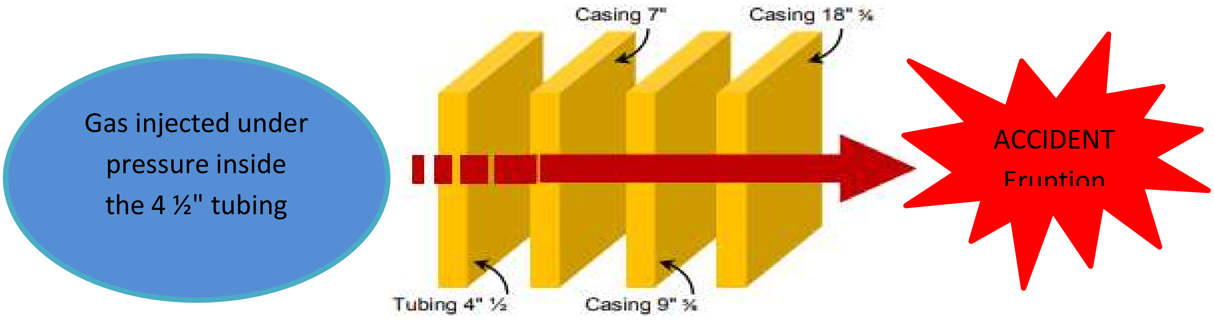


Figure IV.6: Confinement losses through the different annular spaces.

IV.4.1. 1st barrier failure: 4 ½" tubing:

The 4 ½" tubing represents the gas production or injection string. Therefore, it constitutes the 1st mechanical barrier in the well. Because of this, its design must meet technical specifications to withstand all the operating constraints of the well (see Figure IV.7). The rupture of this 1st barrier is schematized as follows:

Change in well status from oil producer to gas injector, not in compliance with integrity.

↓

LTC thread not suitable for gas injector wells.

↓

4 ½" tubing surface displacement.

↓

Leak at 4 ½" tubing.

4 ½" barrier failure.

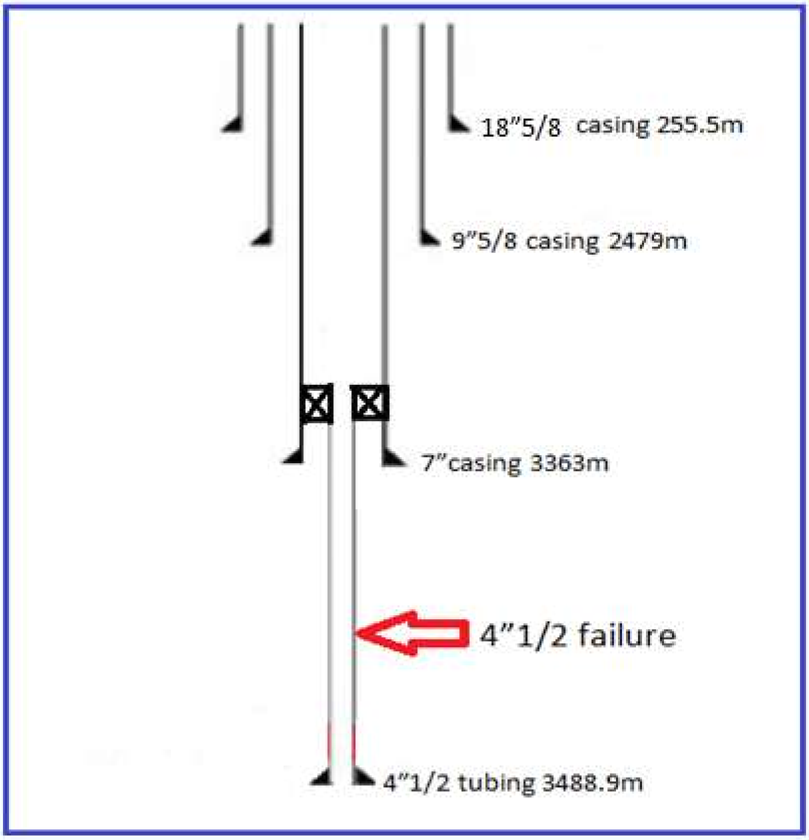


Figure IV.7: 4 ½ failure.

Based on the instantaneous return of mud during post-accident attempts to neutralize the well, the leak at the 4 ½ tubing is most likely due to surface coupling failure caused by the presence of an LTC thread which is not suitable for a gas well, combined with improper cementing of the upper portion of the tubing.

The use of LTC threading (Figure IV.8) and the associated risks were not sufficiently appreciated in the conversion of the well A from oil producer to gas injector.

Figure IV.8: Long thread connection.

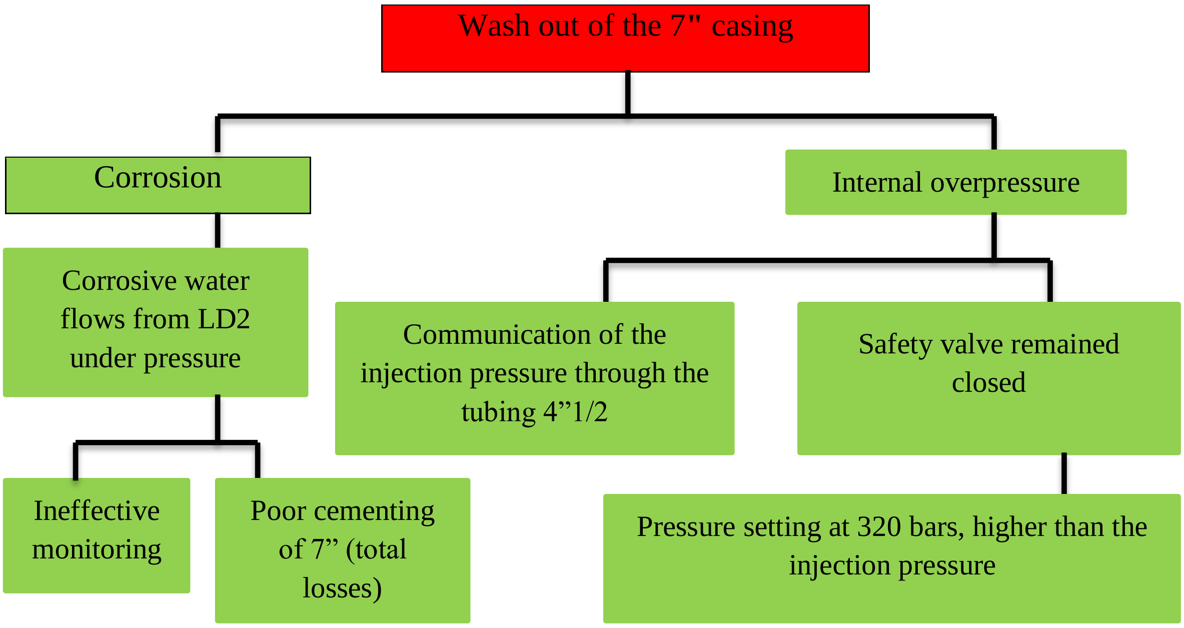
In addition, the incorporation of a seat at the bottom of the well for the reception of a bottom safety valve was made impossible by the cementing to surface of the 4" ½ tubing during the 3rd workover.

The option of the wash out of the tubing due to erosion and/or corrosion was rejected because:

- The first joints shows a good condition of the tubing,
- The 4 ½ liner is considered recent,
- No corrosive fluids present.

IV.4.2. 2nd barrier failure: casing 7".

The 7" casing is an essential mechanical barrier to ensure a seal between the injection or production and the other horizons that may block the proper well exploitation.



7" barrier failure.

The failure of integrity of the 7" casing is mainly due to:

- A corrosion caused by the presence of the calcic chloride waters of the LD2 which occurred after the well was put into production. This manifestation of the LD2 is a consequence of a bad cementing of the 7" casing.(see the Figure IV.9)

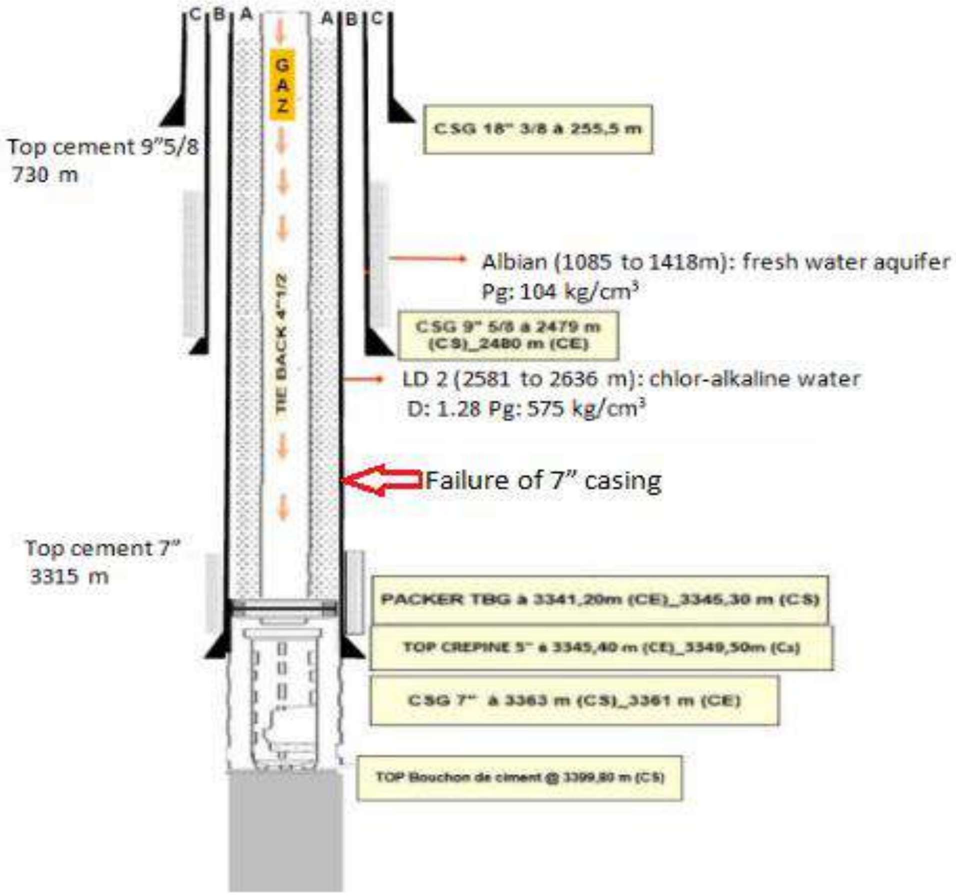


Figure IV.9: Failure of 7" casing.

- The ineffectiveness of the safety valve set at a high pressure much higher than the pressure to which the A annulus was exposed at the time of the accident. In addition, the side outlets of the 7" were blocked. See the Figure IV.10.

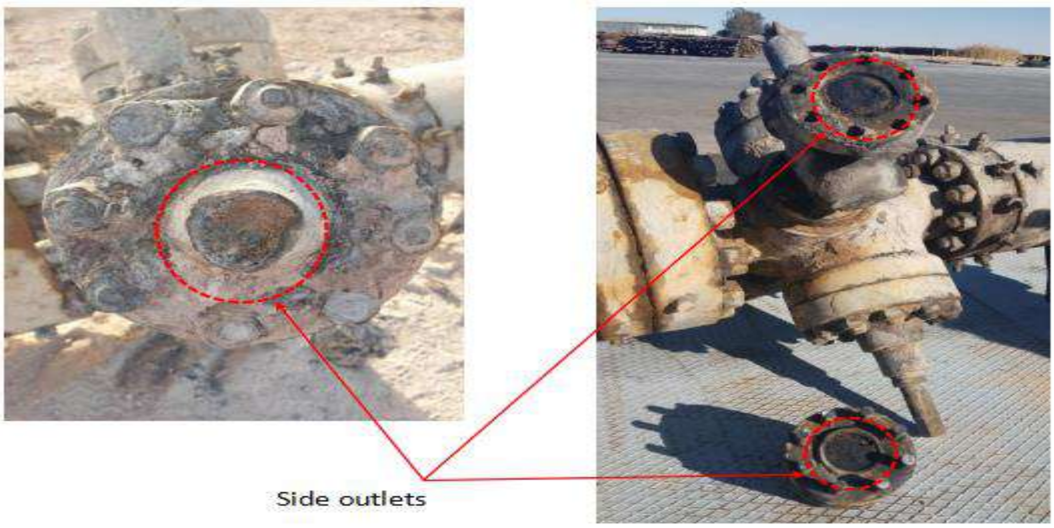


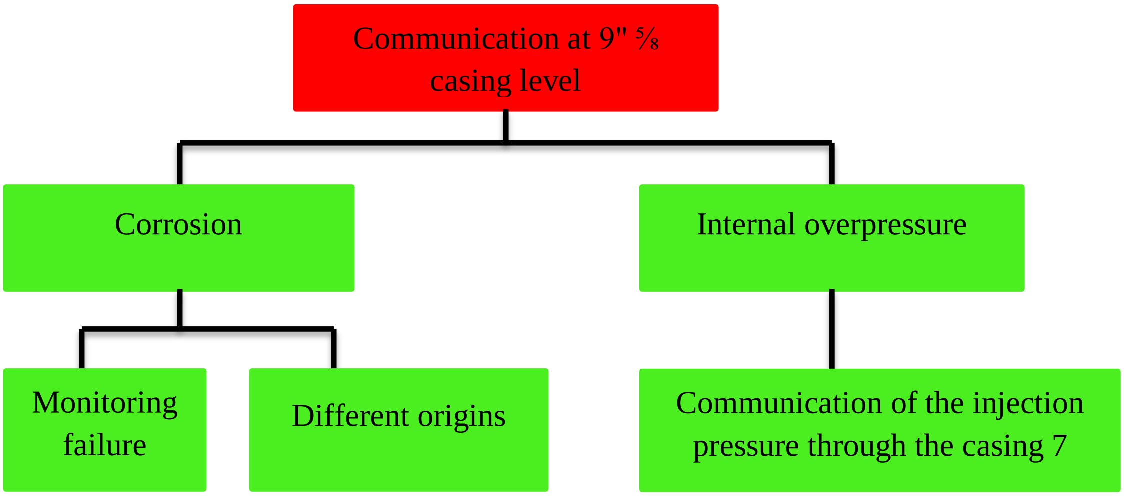
Figure IV.10: Plugging of the annulus a side outlets.

- Ineffective monitoring due to the fact that the annulus is between 4 ½ and 7,, cemented to surface (no corrosion log available).

IV.4.3. 3rd barrier failure: casing 9" ⅝:

The 9" ⅝ casing was lowered into the well to cover the formations incompatible with the LD2 horizon, namely the Albian and Senonian Saliferous. See the Figure IV.11.

The suggested scenario is shown below:



9" ⅝ barrier failure.

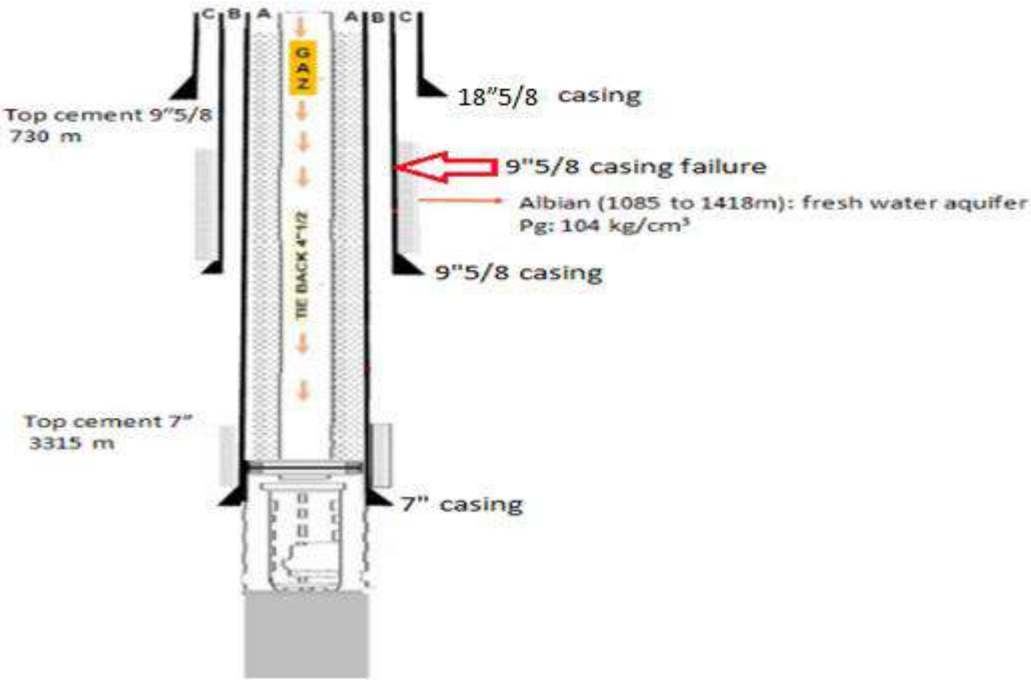
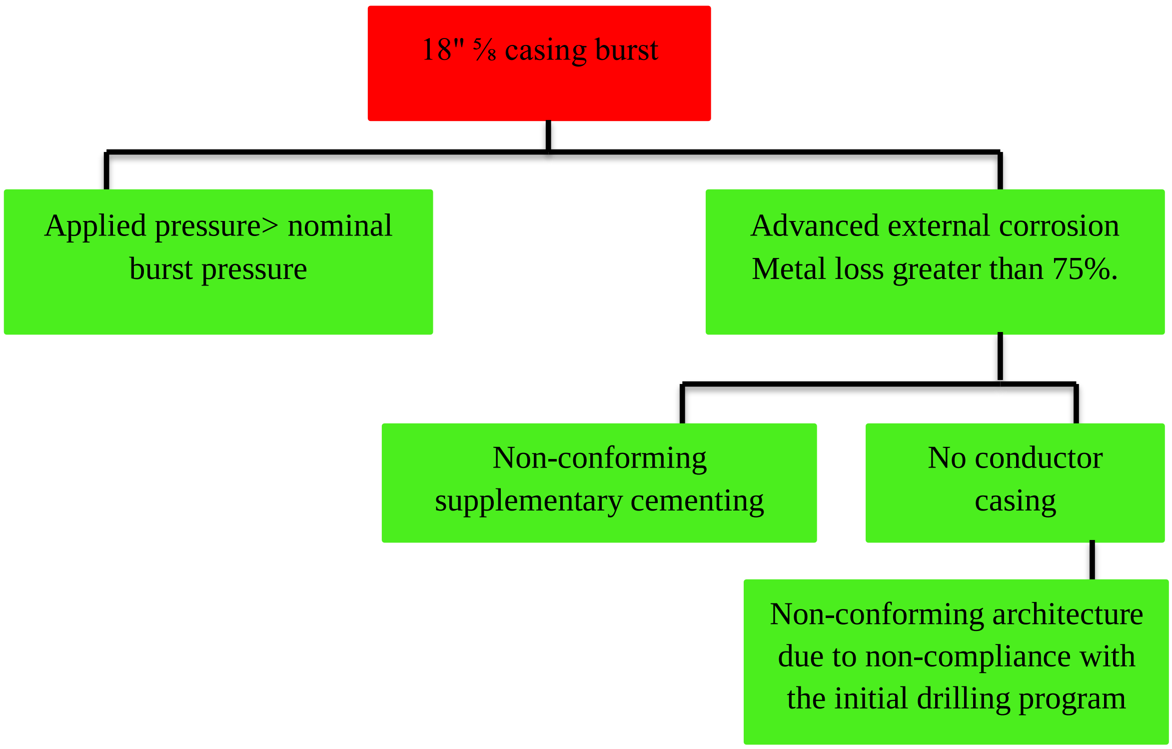


Figure IV.11: 9" ⅝ casing failure.

The failure of 9" ⅝ casing integrity is probably due to internal and/or external corrosion caused by the presence of the various fluids present inside and outside the casing as well as the pressures exerted before and at the time of the accident.

IV.4.4. 4th barrier failure: casing 18" ⅝:

The 18" ⅝ casing is mainly used for consolidation of surface formation. Its mechanical characteristics do not allow it to resist the pressures induced in the well. The failure of integrity of the 18" ⅝ casing is due to its very advanced external corrosion and its non-resistance to the pressure to which it has been subjected. See the figure IV.12.



18" ⅝ barrier failure.

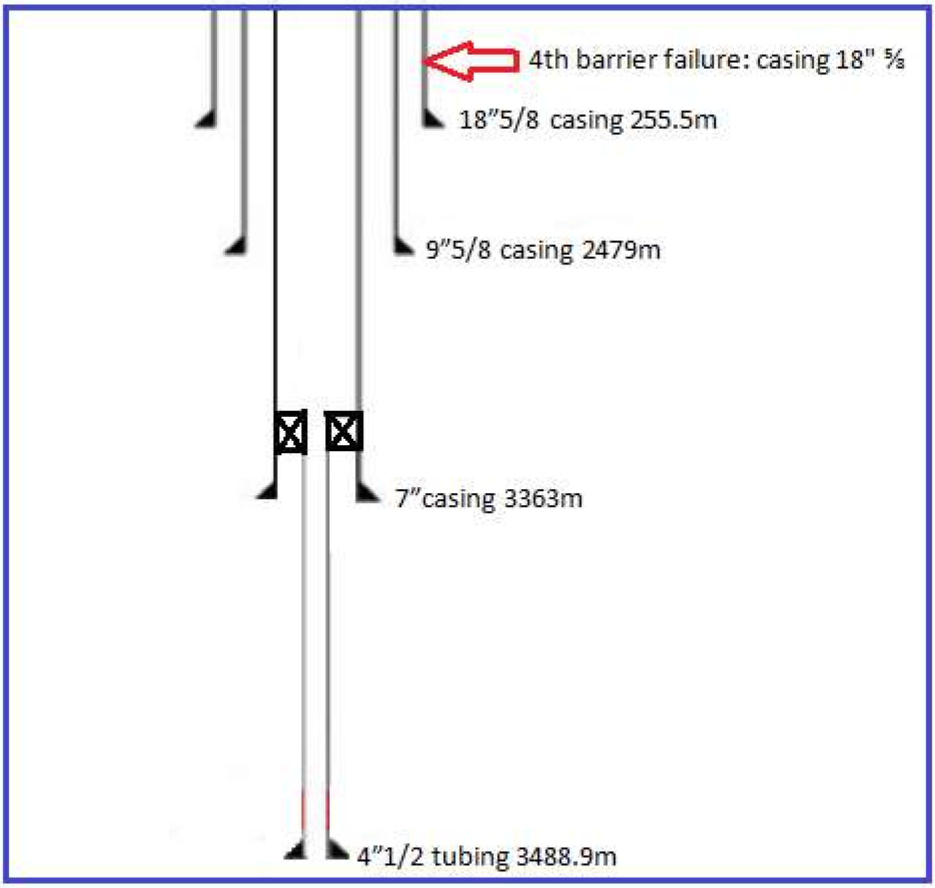


Figure IV.12: Casing 18" ⅝ failure.

IV.4.5. Conclusion of the cause analysis:

The direct cause of this accident was the total failure of the well integrity which was a consequence of a combination of failures such as:

- Well architecture: non-compliance with the initial drilling program
- The suppression of a drilling phase,
- Poor cementing at the LD2 horizon containing chlor-alkaline water,
- The wash out of the 7" casing having led to the cementing of the 4 ½" tubing,
- The use of LTC threads is not recommended for gas wells,
- The absence of a bottom safety valve,
- Conversion of the well from an oil producer to a gas injector without a risk assessment study

- Well monitoring:
  - Inadequacy of the pressure readings of the annuli during the tours compared to the physical reality of the well (the "0 bar" annulus of the tours was not real),
  - Total absence of monitoring of annulus B due to an error in the telemetry connection (Annulus C connected instead of Annulus B),
  - Uncertain indications during tours and those transmitted to the telemetry center,
  - Maintenance of the well surface equipment: very high setting value of the wellhead safety valve, very likely clogging of the manometric intakes and lateral outlets of the annuli.

IV.5. Consequences of this accident:

Health, security and environment:

- No injuries were recorded during this accident.
- The potential consequences are to be considered because of the propagation of the gas to the various sites in the vicinity of the well and which could affect the personnel present.
- Loss of well and surface installations given the condition and response operations undertaken to control the situation, the well could not be returned to exploitation.
- Air pollution by gas, before and after fire

Plus production, cost, time losses.

IV.6. Recommendations:

Following the analysis of the causes and consequences of this accident, we recommend the following:

Regarding well integrity:

- Initiate, without delay, a Risk Assessment on the integrity of gas injector wells that are not equipped with a downhole safety device and have 4" ½ tubing cemented in place,
- Initiate a program to diagnose the integrity and compliance of all wells,
- Make systematic the use of 7" casings with premium connections for new gas injector wells,

- Submit candidate wells for conversion to gas injectors to a Risk Assessment give preference to wells with a premium connection 7" casing,
- Systematize the recording of a deviation profile at the end of each drilling or workover, for possible exploitation.

Wellhead:

- Conduct an inventory of all safety valves installed on the lines and wellheads to protect the "A" annulus. Adapt the set pressure to the exploitation conditions of the well,
- Equip wellheads with automatic valves,
- Strengthen wellhead maintenance operations:

Lubrication, checking the handling of valves, calibrating pressure gauges and de-sanding cellars,

- Supply the Production Division's operational structures with quality and timely wellhead and surface network equipment (valves, nozzles, etc.).

Regarding well monitoring:

- For surface equipment:
- To launch, without delay, a campaign of control and verification of the communications of the annular side outlets of the manometric intakes, of the handling of the valves and the connections of the telemetry installations. To ensure the reliability of the recorded parameters and to take the necessary measures to remedy any anomaly presenting risks on the exploitation of the well.
- Well inspections by specialized third part.

Telemetry:

- Engage actions to improve the exploitation of the current telemetry system such as: connection points, maintenance, visual or audible alarm management, detection of abnormal pressure fluctuations at wells and installations.
- Activate the connection of the remaining wells to the telemetry system.
- Evaluate the needs in humans and material resources for a better management of this system and to remedy them.

IV.7. Conclusion:

In conclusion of this case study chapter, after analyzing discussing the causes of this accident the conclusion is found. The amplitude of this accident and its financial consequences clearly demonstrate that prevention is less costly and simpler to implement. Risk prevention and control require mobilization at all levels to effectively address the failures and short comings identified. It requires special attention in terms of training and availability of adequate means to ensure better quality of the works and efficient operation of the assets to meet the requirements and objectives of quality, costs, deadlines and safety.

Summary and Conclusions:

Well integrity is the quality of a well that prevents the unintended flow of fluid (gas, oil or water) into or out of the well, to the surface or between rock layers in the subsurface. Well integrity is established via the use of barriers that prevent these unintended fluid flows. Two-barrier principle is applied, whereby at least two independent and verified barriers are in place. Unintended or uncontrolled fluid flow will only occur if both barriers fail, resulting in failure of the integrity of the well. Building well integrity management system (WIMS) establishes standardized criteria to guarantee that integrity of all wells is preserved during their lifespan, functions properly in healthy condition and is able to operate consistently to fulfill expected production/injection demands. Moreover, having effective (WIMS) well integrity management system at all times and throughout all well phases reduce the frequency of major integrity failures.

Recommendations:

The risks posed by well integrity issues require proactive management of well integrity. The industry and regulators have increasingly focused on well integrity over the past decade, to improve safety and environmental performance, In particular, the focus has been on managing well integrity across the life cycle of the well, to minimize the risks avoiding none productive time (NPT), costly remedial operations, environment pollution and human casualties. Well integrity management systems should involve:

- Identification of hazards and assessment of risks;
- Clear identification of well barriers at every phase of the well's life cycle;
- Performance standards for well barriers and their components;
- Verification procedures for well barriers against the performance standards; and
- An organizational approach to well integrity management that includes identification of roles and responsibilities, and processes for continuous improvement, change management and audit.

Evaluation and regular periodic monitoring techniques are necessary to provide insight into the evolution of wellbore integrity over time. Well integrity evaluation techniques are based on experiments, logging, analytical and numerical modeling, statistical modeling, and risk analysis.

Monitoring of the operational system including barrier elements, production and completion systems provides the assessment of the well integrity over time in order to develop a sustainable system. The evaluation of dynamic in-situ conditions such as pressure and temperature variation can improve designing a suitable system to cater with the anomalies.

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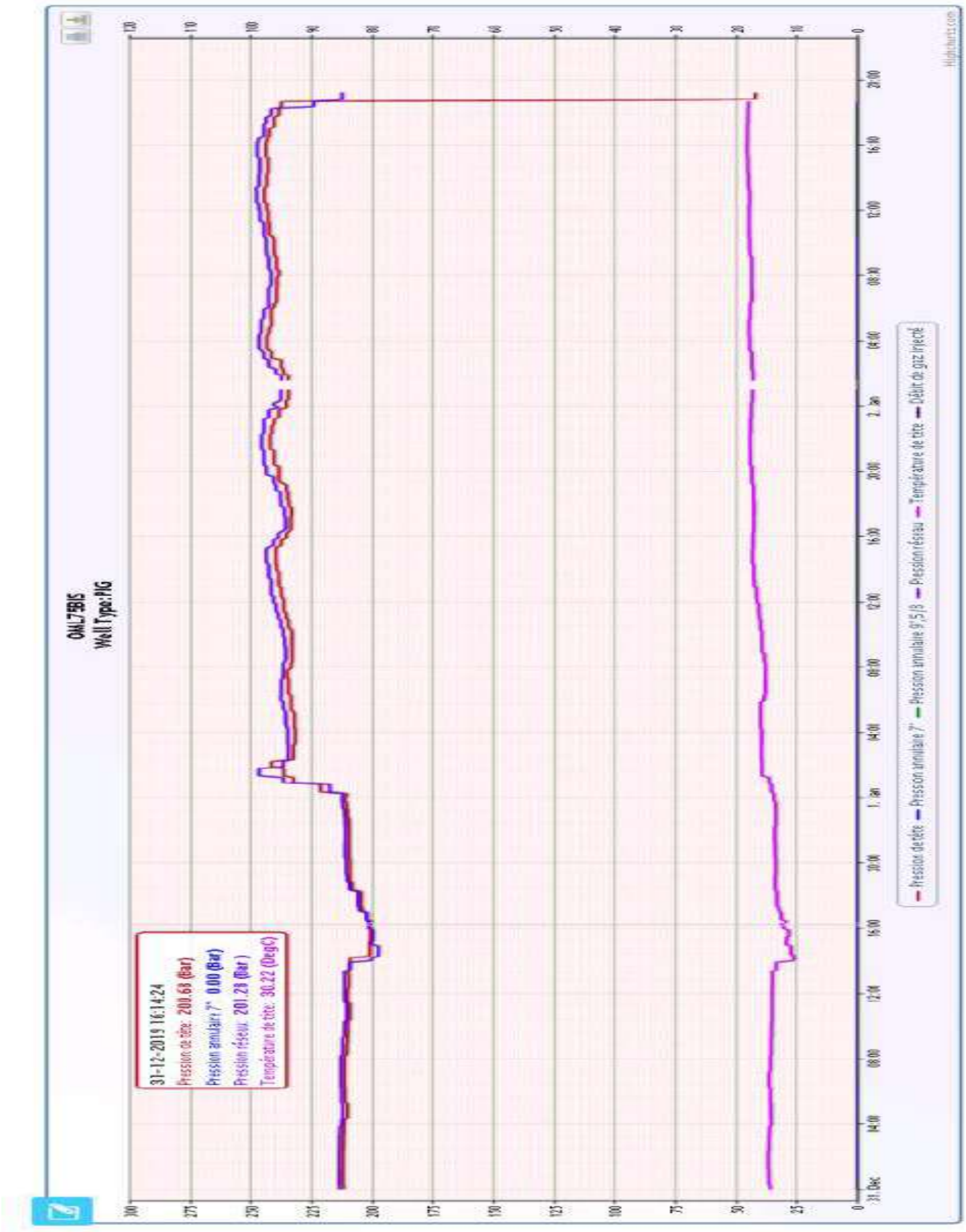
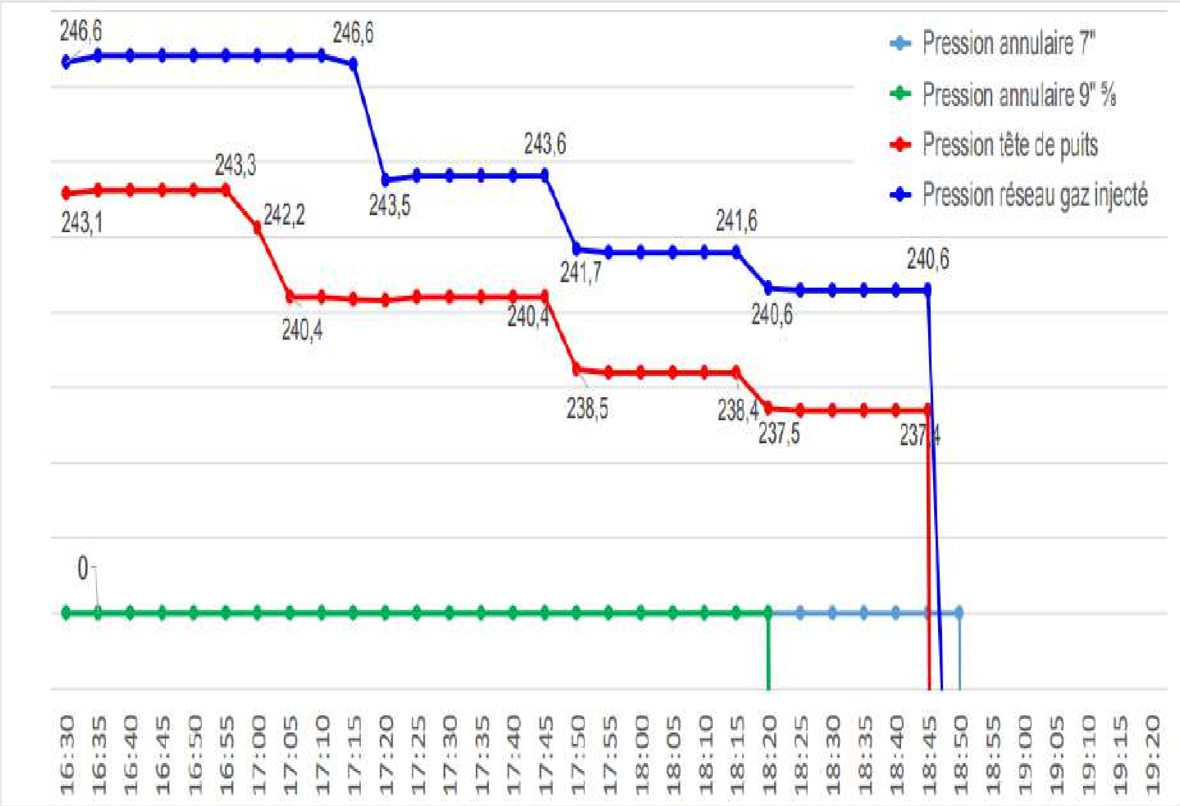
Appendix:

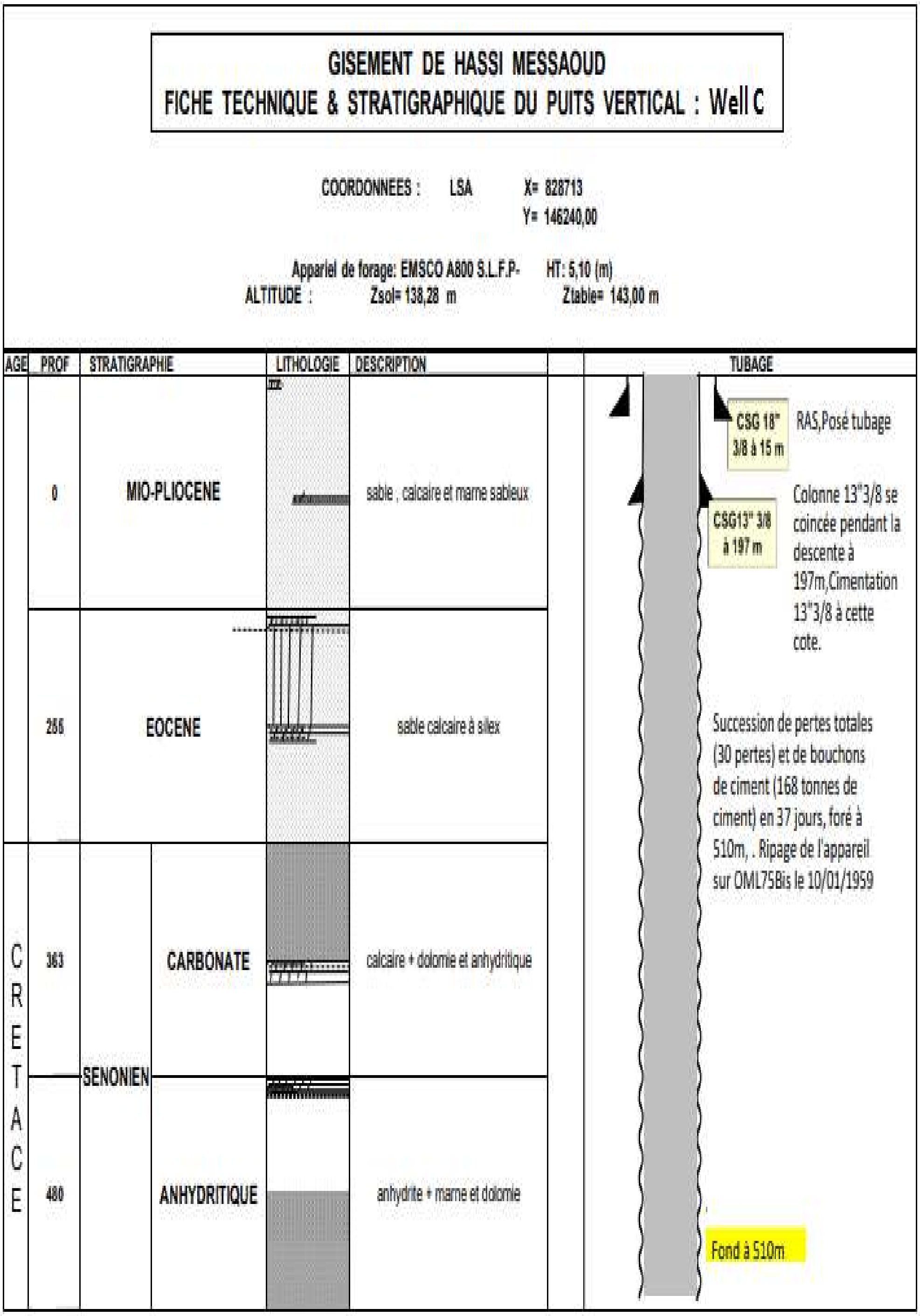
Appendix A: Recorded telemetry readings on January the 1st 2020.



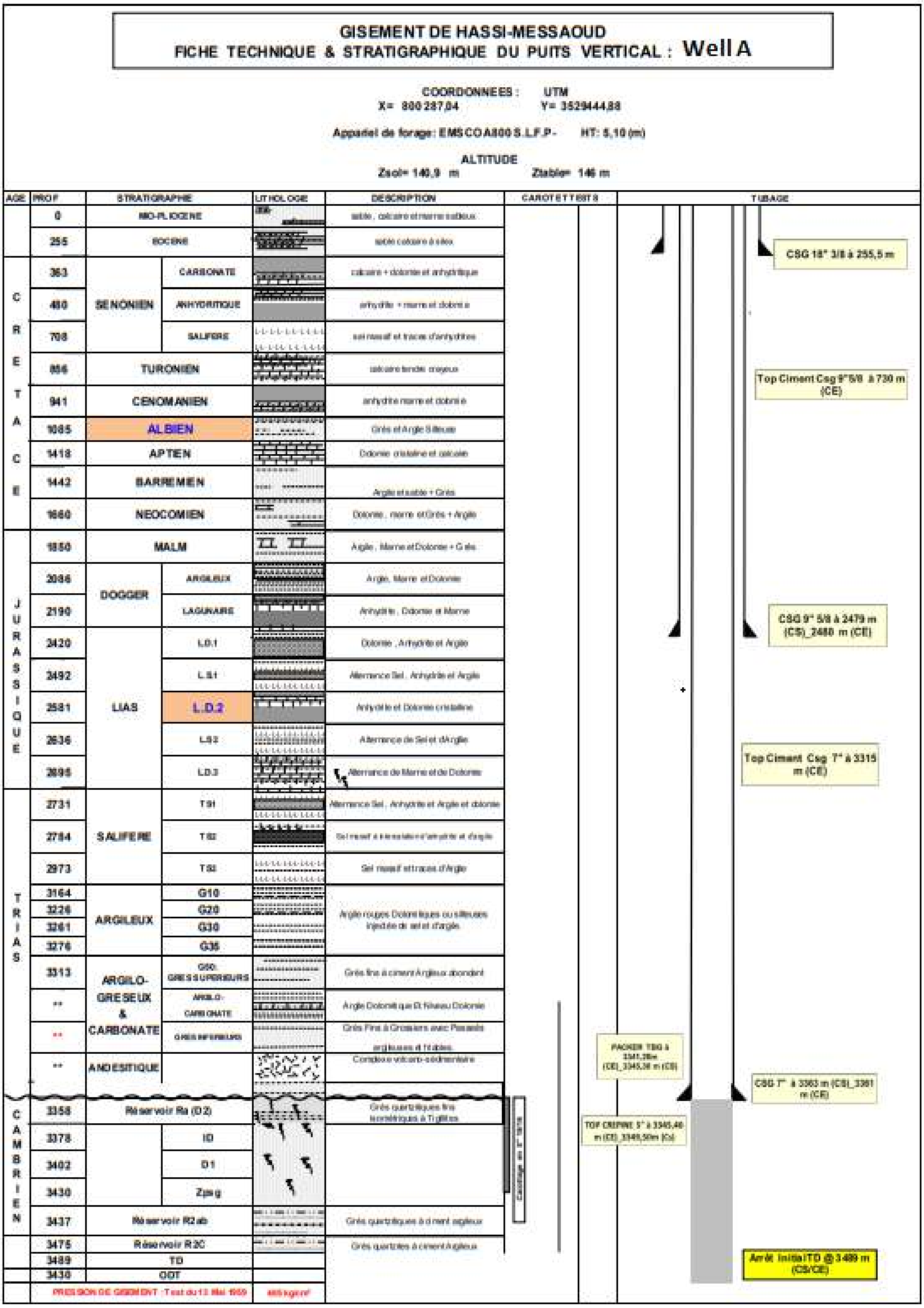
Appendix B: Analysis of telemetry data on January the 2nd 2020.



Appendix C: Stratigraphic section and architecture of well C.



Appendix D: Stratigraphic section and architecture of well A.



Appendix E: Drilling program of well A.

Drilling of the "well A" began on January 16, 1959. Drilling operations were conducted as follows:

• Drilling in 24" to 256 m, without any particular difficulties. Lowering and installation of the 18" casing ⅝ to 255.5 m at the roof of the Carbonate Senonian and cementing with 42 tons of cement,

• Drilling in 12" ¼ to 2480 m, with no particular difficulties and mud loss reported at 275 m. Lowering and setting of 9" ⅝ casing at 2479 m in the Dolomitic Lias (LD1). Cementing in two (02) stages using a DV at 1452 m, with 45 tons of cement (20 and 25 tons). The top cement is at 730 m according to the thermometry operation carried out 12 hours after the cementing operation,

• Drilling in 8 ½", to 3364 m:

- No manifestation of calcium chloride waters in LD2,
- Numerous draws in the right of the fluid clay bench requiring reaming at each descent,
- Total loss of mud in the Triassic, from 3335 m to 3340 m. Plugging with cement plugs.

Lowering and installation of the 7" casing at 3363 m, at the top of the Cambrian reservoir. Cementing with 24 tons of cement, in total loss. The cement top is at 3315 m according to the thermometry operation carried out 17 hours after the cementing operation.

• Drilling and coring in 6" to 3489 m. No particular problems were reported. Cambrian sandstones were cored over 128 m from 3360 to 3488 m.

- Cambrian thickness R1= 78 m. Cambrian thickness R2= 51 m,
- Results of the DST operations: oil flow of 10.6 m3 /h on a 6.4 mm nozzle with a head pressure of 226 kg/cm2.

• Completion of the well:

- Tank left in Open Hole,
- Completion with 4" ½ LTC tubing, anchored in 7" casing with 3" ½ NU under packer extension.

The well was delivered on May 27, 1959.

The evaluation of the cementing of the "well A" shows the following:

• Casing 18" ⅝, no cementing evaluation log,

• Casing 9" ⅝, the cementing control was carried out with a thermometry log recorded on March 09, 1959, 12 hours after the end of the cementing operation. It indicates a cement top at 730 m located in the right of the Senonian Saliferous.

The Albian located from 1085 m to 1418 m, is covered by cement,

• Casing 7", the cementing control was carried out with a thermometry log recorded on 19 April 1959, 17 hours after the end of the cementing operations. It indicates the presence of cement over a height of 45 m only from shoe 7", i.e. a cement top at 3315 m. The rest of the column is not cemented,

The LD2 level, located from 2581 m to 2636 m, is not covered by cement,

• A CBL cementing log recorded on May 25, 1963, during a workover operation, confirms good cementing on 12 m only above the 7" shoe and poor cementing on the rest of the column.

On the drilling and cement job evaluation phase we noticed:

• Missing guide tube in well A,

• Change in the drilling program on well A, as compared to the Implementation Report. This results in the following:

- Drilling in phase 24" instead of 22" and laying of casing 18" ⅝ (planned guide tube) in place of casing 13" ⅜, i.e. at elevation 255.5 m,
- Removed 17" ½ phase with 13" ⅜ case and went directly to 12" ¼ phase,
- Non-compliant fitting of the 18" ⅝ casing to the 20" ¼ x 3000 casing head housing by fitting a welded flange,
- Non-conforming fit of welded flange to 13" ⅝ x 3000 casing head housing.

• Cementing of the 7" casing in one (01) stage instead of two (02) stages, as planned in the initial drilling program,

Total loss during cementing. Only 12 m above the shoe were well cemented. All the rest is very bad (free pipe).

• Absence in the "well A" well file of some important information such as steel grades and nominal weight for casings.

Appendix F: Workover operations on well A

Since it came on stream in 1959, the well A has undergone three (03) workovers.

• The 1st workover was to change the completion following a hole in the 4" ½ tubing and to insulate the water area to address the increased oil salinity.

- Notes: Nothing to report.

• The second workover was to lower a liner with a strainer to prevent excessive sand from coming in.

- Highlights: Nothing to report.

• The 3rd workover was carried out after the LD2 communication through the 7" case was detected.

After this operation we noticed:

- Annular space test not performed.
- LD2 communication through the 7" case not located.
- Cementing the 4 ½" to the surface.
- Quality of cementing of 4" ½ tubing: good overall, from Packer 4" ½ from 3345m to 1998m. Poor from this elevation to the surface. Good cementing opposite LD2.

Other Operations on Well A:

• The first snubbing operation was carried out with the aim of lowering a 1"660 Concentric for the injection of desalination water,

• The 2nd Snubbing operation for the 1"660 Concentric was carried out. Also, the 10,000 psi series Christmas tree was changed,

•A stimulation operation carried out in order to bring gas injection into service.

Notes:

• No seat in the 4" ½ tubing for the installation of a bottom safety valve.

• Annular space test not performed.

• The type of thread of the tubing is not adequate (LTC instead of VAM).

The "well A", which began production in October 1959, has accumulated production of 4.28 million m3. The evolution of the production of this well.

Notes:

- The well was shut-in in April 1996 following a reduced oil flow to 0.7 m3 /h and a gas breakthrough,
- For reservoir needs in Zone 9 (pressure maintenance and miscibility), it was decided in 2001 to convert the "well A" into a gas injector.

The well A, which was injected in May 2001, had no apparent problems or incidents during the entire injection period, until the occurrence of the accident on January 2, 2020.

Abstract : harsh locations and downhole conditions pose severe challenges for ensuring safe and long-lasting intact well conditions. Well integrity is a crucial issue ina well life cycle. Failure to obtain and maintain adequate well barriers integrity could led to catastrophic events, negative financial consequences, and environmental impacts, such as groundwater contamination, gas leakage to the atmosphere, and fluid spills and seepage at the surface.Wells must be designed to ensure well integrity, i.e. that the fluids stay contained within the wellbore, and that the surrounding subsurface layers, including aquifers, are protected. Well integrity is a result of technical, operational and organizational barriers applied, with the intention to contain and control the reservoir fluid and well pressures.Managing well integrity is essential to economically develop oil and gas resources while preserving the environment and assuring safety to personnel, by focusing on the development of systems and processes to manage the well operations and interventions to assure well integrity with many claims to have a workable system that verifies and confirms the status of wells with suspect integrity. In this thesis, an investigation on well integrity failure lead to major accident, accompanied with cause analysis discussion.

Key words: well integrity, well barriers, well integrity management, Failure Analysis.

Résumé: les endroits difficiles et les conditions de fond de puits posent des défis importants pour assurer la sécurité et la pérennité de l'intégrité des puits. L'intégrité des puits est une question cruciale dans le cycle de vie d'un puits. Si l'on ne parvient pas à obtenir et à maintenir une intégrité adéquate des barrières de puits, cela peut conduire à des événements catastrophiques, à des conséquences financières négatives et à des impacts environnementaux, tels que la contamination des eaux souterraines, les fuites de gaz dans l'atmosphère, les déversements de fluides et les infiltrations à la surface. La gestion de l'intégrité des puits est essentielle pour développer économiquement les ressources pétrolières et gazières tout en préservant l'environnement et en assurant la sécurité du personnel, en se concentrant sur le développement de systèmes et de processus pour gérer les opérations de puits et les interventions pour assurer l'intégrité des puits avec de nombreuses revendications pour avoir un système viable qui vérifie et confirme le statut des puits à intégrité suspecte. Dans cette mémoire, une enquête sur la défaillance de l'intégrité du puits qui a conduit à un accident majeur, accompagnée d'une discussion sur l'analyse des causes.

Mots clés : intégrité des puits, barrières de puits, gestion de l'intégrité des puits, analyse des défaillances.

الملخص: تشكل المواقع القاسية وظروف قاع البئر تحديات خطيرة لضمان ظروف جيدة آمنة وطويلة الأمد فسلامة الآبار هي قضية حاسمة في دورة حياة البئر وقد يؤدي الفشل في الحصول على سلامة حواجز الآبار الكافية والحفاظ عليها إلى أحداث كارثية وعواقب مالية سلبية وآثار بيئية مثل تلوث المياه الجوفية وتسرب الغاز إلى الغلاف الجوي وانسكاب السوائل والتسرب على السطح أي أن السوائل تبقى محتواة داخل جوف البئر وأن الطبقات الجوفية المحيطة بما في ذلك طبقات المياه الجوفية محمية لسلامة الآبار هي نتيجة للحواجز التقنية والتشغيلية والتنظيمية المطبقة بهدف احتواء والتحكم في سائل المكمن وضغوط الآبار وتعد إدارة سلامة البئر ضرورية لتطوير موارد النفط والغاز اقتصاديًا مع الحفاظ على البيئة وضمان سلامة الموظفين من خلال التركيز على تطوير الأنظمة والعمليات لإدارة عمليات البئر والتدخلات لضمان سلامة جيدة مع العديد من الادعاءات بأن لديها نظام عملي يتحقق ويؤكد حالة الآبار المشتبه في نزاهتها في هذه المذكرة ويؤدي التحقيق في فشل سلامة البئر إلى وقوع حادث كبير مصحوبًا بمناقشة تحليل السبب.

الكلمات الأساسية: سلامة البئر ، حواجز الآبار ، إدارة سلامة الآبار ، تحليل الفشل.