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Revealing the Cause behind Cement Failures by Means of the Knowledge Model of Oil Well Drilling

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Abstract

Safety improvement is a topic under a continuous focus offshore. To reduce the number of accidents, improvements are approached in several ways. Accident reports are analyzed, human factors are studied in depth and the companies are investigated, *after* the incident has occurred. An improved method of evaluation is now under consideration, which has the potential of being run in real-time and obtain an immediate pre-assessment of the failure. This method is based on a knowledge model of the drilling process, where all concepts involved in the process are structured in hierarchical categories, based on established knowledge combined with situation specific experiences. The concepts are clearly defined and related to other concepts if there exist any causal relation between them.

Cementing issues is one of the greatest challenges regarding well integrity. By applying the knowledge model and expand it to encompass the details of the cementing process, an ability to recognize progressing downhole problems is created, and symptoms seen at the surface can be related to all relevant types of cementing problems. This allows for preventing actions to be initiated at an early stage.

In this report a knowledge model for cementing issues has been constructed based upon textbook knowledge, and further expanded by analyzing five incidents where the cement job failed. The incidents were later tested by means of the knowledge model to find the most probable cause of the failures. Symptoms interpreted from investigation reports were used as input for the model which revealed the main cause and the most probable underlying causes of the incidents.

Sammendrag

Bedring av sikkerheten offshore er et tema under konstant fokus. For å redusere antall uønskede hendelser må prosesser hele tiden forbedres, noe som kan gjøres på mange forskjellige måter. Ulykker granskes og ulykkesrapporter utarbeides. Menneskelige faktorer og selskapenes kontrollsystemer studeres i dybden, alt dette *etter* at den faktiske hendelsen har forekommet.

En ny metode for evaluering av uønskede hendelser er nå under arbeid. Denne metoden er mulig å kjøre i «real-time» slik at man får en advarsel før ulykken inntreffer, og dermed kan gjøre nødvendige tiltak for å unngå hendelsen. Metoden er basert på en kunnskapsmodell hvor konsepter er strukturert i hierarkiske kategorier, basert både på etablert kunnskap og på situasjonsspesifikke erfaringer.

I denne Masteroppgaven skal en kunnskapsmodell for sementrelaterte problemer utarbeides og senere testes. Sementering og problemer relatert til denne prosessen er en av de største utfordringene når det kommer til brønnintegritet. Ved å anvende kunnskapsmodellen i sementeringsprosessen oppstår muligheten for å oppdage pågående problemer i borehullet ved å implementere symptomer sett eller målt på overflaten. Tiltak kan dermed startes på et tidlig tidspunkt.

Kunnskapsmodellen som her utarbeides og presenteres er basert på kunnskap fra lærebøker og sementrelaterte studier. Situasjonsspesifikk kunnskap fra fire ulykker i Mexicogolfen og en ulykke på den norske kontinentalsokkelen er brukt til å ekspandere modellen. Symptomer funnet i ulykkesrapportene fra hendelsene er brukt som inndata i modellen, slik at den kan beregne de mest sannsynlige årsakene til ulykkene.

Preface

This thesis is written at the Department of Petroleum Engineering & Applied Geophysics at the Norwegian University of Science and Technology. It is the work completed in TPG4910 Drilling Engineering Master's Thesis and was written during the autumn of 2014.

The present thesis has been both educational and challenging. During 22 weeks of researching and writing I have obtained a lot of experience and an insight to the complicated world of cementing processes.

I would like to thank my supervisor Pål Skalle (Associate Professor, Drilling Engineering, NTNU) for all help, guidance and feedback through my working period. I also wish like to thank my little family; Jakob and Serhat for the patience and for being the sunshine in my life.

Trondheim, February 2015

Lise Løw Løhre

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1 Introduction

Cementing of a well is a sensitive and complicated process, and well cement constitutes an essential barrier in the borehole that can be difficult to achieve. As the easy hydrocarbon fields are maturing, the production rates of the wells are declining. New discoveries are emerging primarily in areas representing complex challenges like depleted reservoirs, HPHT fields, extreme temperatures and pressures, unconventional source rock and fields in ultra-deep water. The well operations consequently gets more prone to errors, and the need for a well-functioning cement job is more important than ever.

The construction of oil and gas wells relies on multiple layers of steel and cement barriers to ensure safe operations. Primary cementing is a critical operation during well construction, and the main objective of this job is to provide effective casing support and zonal isolation allowing the hydrocarbons to be produced safely and economically. A good primary cementing job is critical for the well integrity throughout the life of the well. Failures occur, and non-productive time (NPT) represents large parts of the total rig time. With daily rates of an offshore well at approximately 300 000 US $/day (Rigzone 2014), recognizing and diagnosing of evolving downhole errors at an early stage will benefit the industry both economically and safety-wise.

Knowledge modelling is a general method of assisting the complex operation of drilling an oil well. The Knowledge Model of Oil Well Drilling (DrillKM) is applied by collecting, reusing and sharing the knowledge of the drilling operation. The DrillKM contains concepts and relations between them. The relations are made between symptoms of un-normal situations seen at the surface and the resulting errors and failures these may cause. By means of the DrillKM, the failure cause can thus be determined based upon symptoms and other model internal concepts relevant for the failure. New relationships can be stored in the model to be used for similar future error/failure causes.

The goal of this study is to reveal the causes behind serious leaks in cemented annuli. The goal is planned to be reached through these steps:

1) Develop a knowledge model for cementing operation challenges, and fit it into the existing DrillKM. The cement model will initially be based upon general knowledge found in textbooks, and the cementing problems found will be evaluated and related to cause groups. This type of knowledge building is called top down modelling.
2) Study cases of cement leaks. The knowledge revealed in these cases will represent more specific knowledge. Entering such knowledge into the model is called bottom up modeling.
3) By means of the DrillKM, the different cases of leaks will be evaluated and analyzed to determine the most probable causes of the problem. The determined causes will be compared to the report conclusions, and thus we can test the method's quality.

With this plan we have taken a step towards the development of an on-line method of cement problem prediction.

2 Published Knowledge on Failure Detection

Leakages can occur during all the different well phases; installation, testing, intervention, injection and production. The time and the ongoing activity at the leakage breakout are important factors in order to find the cause. A failure during the drilling operation is defined as the state when NPT is occurring. Typically, NPT is in the range of 20% of total rig time, but can become much higher during drilling of difficult wells (Halliburton 2014). Being able to reduce this time during drilling and to improve process quality are the concerns of many researchers and engineers. Diagnosis is especially important in complex wells, in which the diagnosis is not obvious and problems therefore takes time to resolve.

The structured knowledge will be based on the existing DrillKM (Skalle et al., 2013), and will in this thesis be exemplified on cement problems.

2.1 Knowledge Engineering in General

Knowledge engineering, or Ontology engineering, has in the recent years been a method of reusing and sharing knowledge. Ontology is a term used in philosophy, encompassing the study of what "it" is. The application of Ontology within Information Technology and engineering is more recent, and has replaced and enhanced terms like knowledge model, data model, term-catalogue, etc. (Skalle et al.,2013).

All ontologies make some assumptions about the world that they represent. The ontology presented here can be viewed as a schematic network, where each node in the network corresponds to a concept and each arrow to the relation between the concepts (Fig. 2.1). The top level concept 'Thing' stands for anything in the world worth naming or characterizing. Everything we want to talk about is a subclass or instance of this concept. Thing has basically two subclasses; Entity (objects in the world) and Relation (bi-directional relations between entities). In addition a third subclass is introduced; Descriptive Thing (a syntactical or structural description of the entities).

The DrillKM is developed based upon the theory of ontology engineering. The model makes it possible to reveal the main cause of restrictions or other problems occurring during drilling. According to Aamodt (2004) the DrillKM is a combination of top-down and bottom-up approach. Top down is the initial knowledge process and bottom-up is when the model learns when new cases are solved.

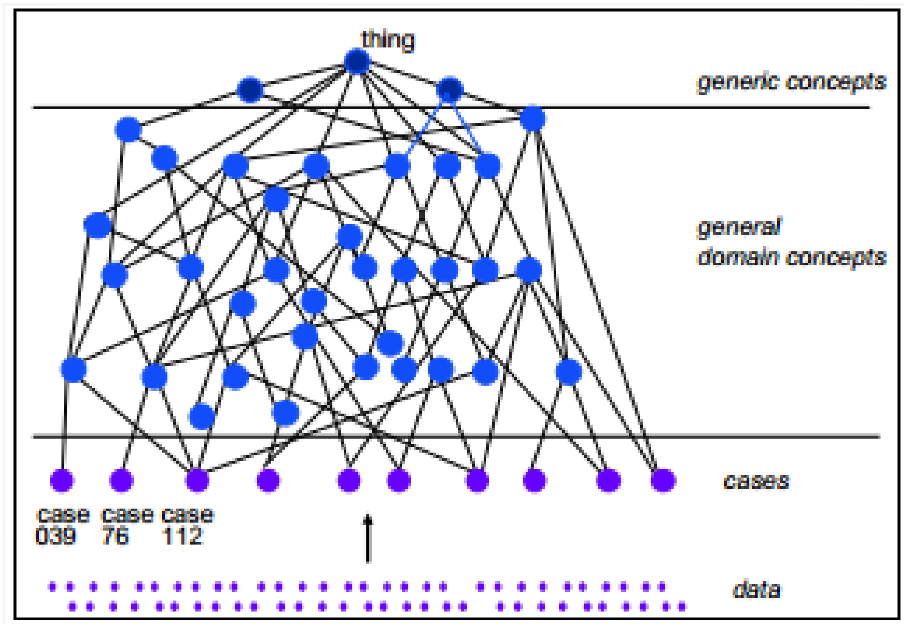


Fig. 2.1: Example of an ontology. General knowledge is in the upper levels and specific knowledge in the lower levels. The most specific knowledge is stored in cases defined by the process data (Aamodt, 2004).

2.2 Technical Error and Failure in the Drilling Process

To understand the coming models some central concepts have to be defined:

Table 1: Central concepts of the DrillKM.

Concept	Explanation
Normal State	The state in which a process or entities are performing as expected
Symptom	An indication of a problem situation
Error State	A state in which a process or a facility or its components are less functional or stop functioning, but do not necessarily cause any significant loss of time.
Failure State	A significant unplanned stop in the process or merely reduced process efficiency occurs, and thus a significant NTP is involved. NPT is normally a result of a repair activity, the activity necessary to bring the process back from Failure State to Normal State

Fig. 2.2 demonstrates how the mentioned concepts of Table 1 are related to each other during a drilling operation. Encountering a symptom will shift the drilling operation from Normal State to Error State. Most symptoms are self-rectifying, and brings the process back from Error State to Normal State.

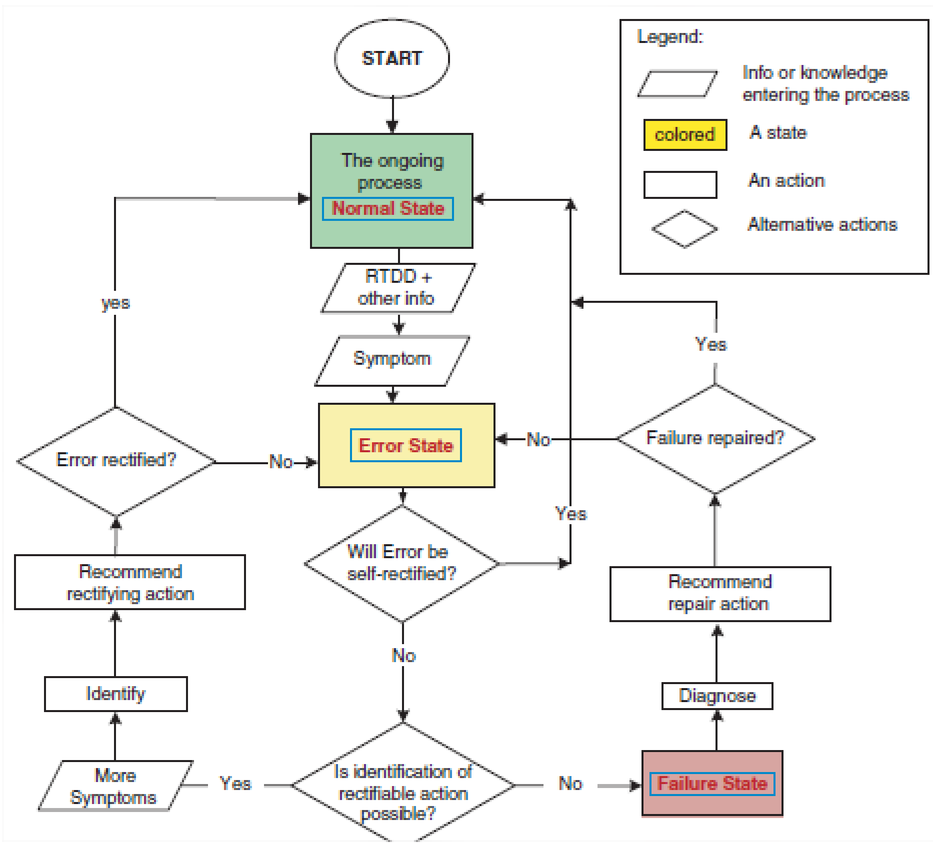


Fig. 2.2: Possible process states during drilling, from Normal State via Error State to Failure State (Skalle 2012).

2.2.1 Errors and Failures

Before a failure occurs the drilling process enters into an error state. Fig. 2.3 demonstrates a subclassification of technical errors in the drilling process. An error occurs when a parameter, a process or an object exhibit a deviatory performance. The deviation may rectify itself or it may be persistent, so that it leads to a failure in the long run.

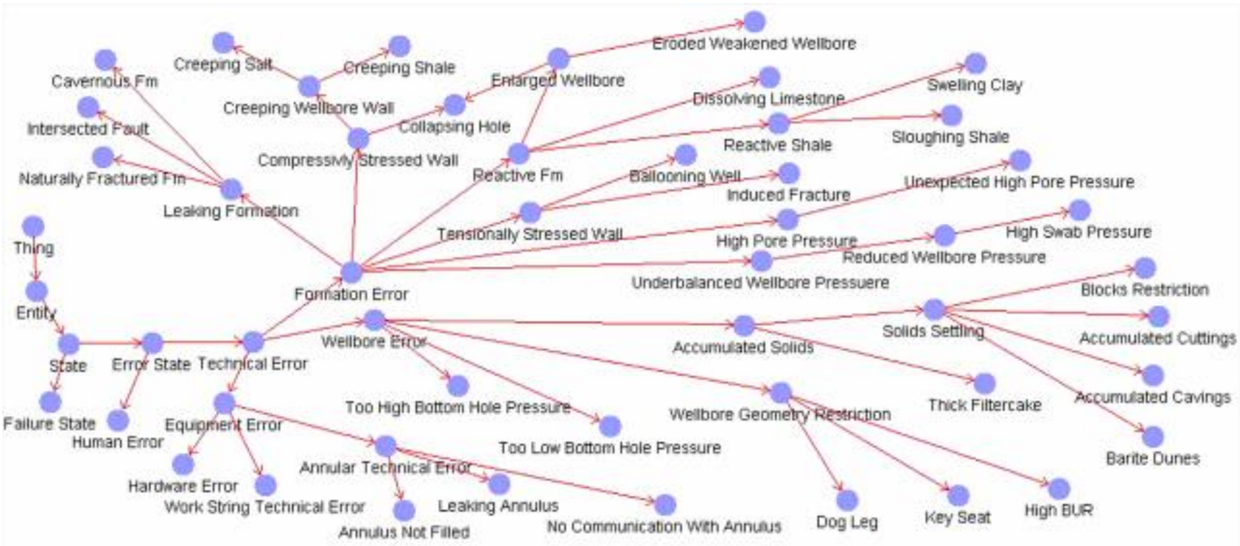


Fig. 2.3: Subclasses of technical errors in the drilling process (Skalle 2012).

By means of the DrillKM it is possible to model rather complex mathematical relationships. The model is not depending on recorded parameters, but is sufficient to understand the physics involved and model it as a relationships between concepts.

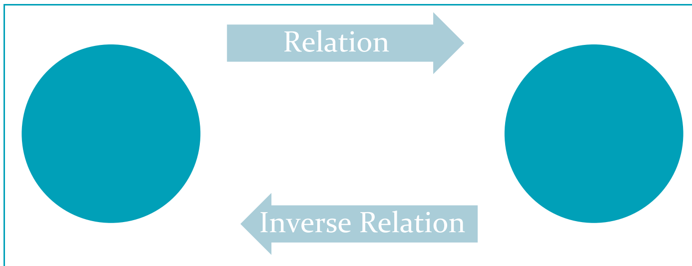
Failures are grouped in accordance with where they take place and classified. Figure 2.4 presents an example of how this is done. Failures are the end state and the focus of accident investigations, being results of both technical and human errors.

Fig. 2.4: Subclassification of failures in the drilling process (Skalle 2012).

2.2.2 Relations

The symbolic concepts will be related through different relationships. The relations are created depending on the strength between the concepts and its subclass. The strength of the relationship represents the certainty/uncertainty of the relation between two symbolic concepts. It is possible for all relations to be inversed, i.e. “A causes B” can also be expressed as “B is caused by A” (Abdollahi 2007). Table 1 gives and overview of the relations and their numerical value.

Table 2: Relations and strength between entities. Inverse Relation have the same strength as Relation (Abdollahi 2007).



Relations	Subclass	Strength
Structural	has subclass	1.0
	has synonym	1.0
Causal	causes always	1.0
	causes	0.9
	leads to	0.8
	implies	0.7
	causes sometimes	0.6
	enables	0.5
	reduces effort of	0.5
	involves	0.5
	Indicates	0.4
	causes occasionally	0.3

2.3 Determine the Most Probable Cause of Failure

Symptoms are anomalous parameters and indications of a problem situation. The result of a case and its symptoms, and to which error these are pointing the strongest towards is a numerical value. Each of the relationships connecting the symbolic concepts to each other has a specific value. This value represents the path and is the product of the strength of each relationship from the first symbolic concept to the failure. The relationship between the observation and the symbolic concepts is always equal to 1 (Skalle 2012).

$$Path\ strength = \prod_{i=1}^{n} relation\ strength_i \tag{2.1}$$

Where n is the number of relations in the path.

The final step in creating the DrillKM is to relate the symbolic components to their error/failure. This is done by calculating the explanatory strength. This strength is found by adding all the paths that lead to the same error/failure (Skalle 2012), and this is being done by equation 2.2. By calculating the explanatory strength for each error, the result will show how each restriction is related to the failure.

$$Explanatory\ strength = \sum_{j=1}^{m} path\ strength_j \tag{2.2}$$

Where m is the number of paths leading to the failure.

When the classification of the failures are completed, the next step is to pick out the correct class on the basis of its symptoms and other case features. Step 1 is to embed the observations in the selected case into the DrillKM. To exemplify the determination of the failure cause a problem due to restrictions in the wellbore (Skalle et al. 2012) will be used in the next subchapter.

2.3.1 Example on Failure Cause Determination

A typical drilling operation starts of in the vertical direction, but deviates quite often in an almost complete horizontal direction. The restrictions are bound to occur during the different process activities, unless signs of restrictions are detected and properly tended to. Observations, errors and failures are related in the ontology through intermediate concepts, along cause-effect chains as shown in Fig. 2.5. Two error types which most often are related to the failure Improperly Cleaned Well are picked out; Reacting Formation and Accumulated Solids. These error types and their subclasses are summarized in Table 3.

Table 3: All potential errors which could be causing the two error types Reactive Formation and Accumulated Solids (Skalle et al. 2012).

Error group	**Subclass**	**Subclass**
Reactive Fm	Enlarged Wellbore	Erosion of Weakened Wellbore
	Dissolving Limestone	
	Reactive Shale	Sloughing Shale
		Swelling Clay
Accumulated Solids	Increasing Filtercake	
	Solids Settling	Chunks in Wellbore
		Accumulated Cuttings
		Accumulated Cavings
		Barite Sag

One case, named WF023, was selected for demonstrating the methodology. The relevant symptoms and observations in the case were picked out:

Table 4: Relevant symptoms and observations of Case WF023.

Low Mud viscosity
Very Long Open Hole Time
Pack Off
Took Weight
Low ROP
Increasing Drag
Low Well Inclination
Low Well Inclination

The observations were then imbedded in the DrillKM, as demonstrated in Fig. 2.5. Internal relationships relate them to potential Errors and Failures. From all the observations there is a path either directly or indirectly to two different root causes; Swelling Clay and Cuttings Accumulation.

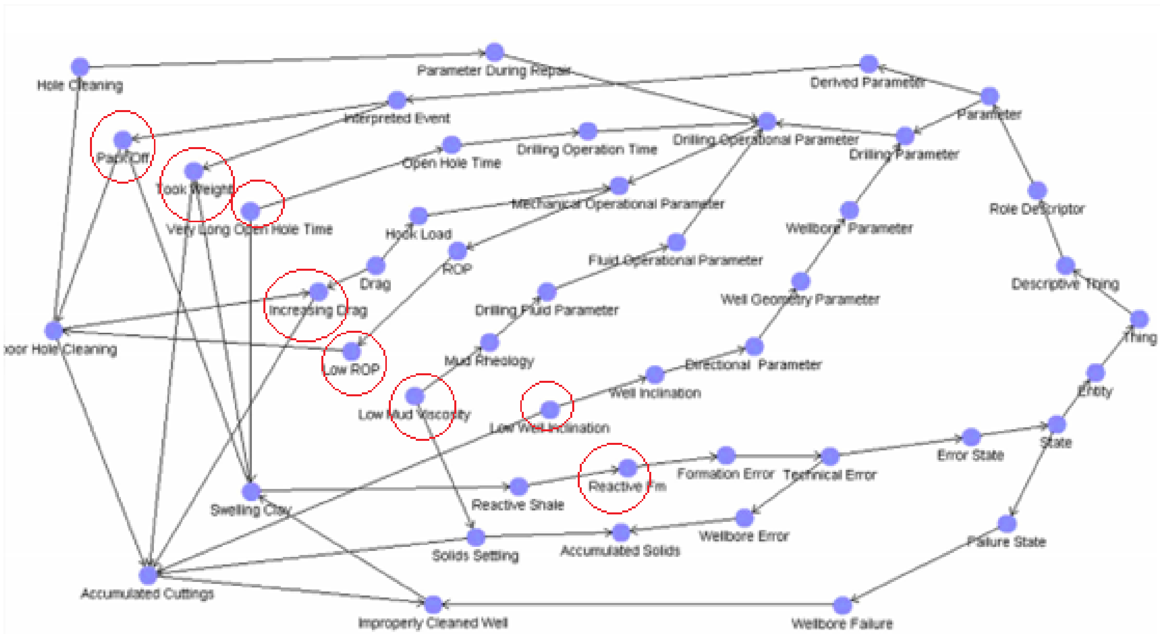


Fig. 2.5: The relevant observations (circled) during the episode are pointing to two errors. Accumulated Cuttings and Swelling Clay point with different explanation strength to the failure Improperly Cleaned Well. The arrows represent many different relation types, e.g. "causes sometimes" and "has subclass" (Skalle 2012).

The strength of the paths are then calculated from equation (2.1) in section 2.2. The results are presented in Table 5. The longer path, the weaker path strength. The total explanation strength for each target entity is determined by adding all paths leading to the specific target error as shown in Table 5. It shows that the probability of the only two activated causes is:

Accumulated Cuttings: 62%

Swelling Clay: 38%

Table 5: All potential errors which could be causing the two error types Reactive Formation and Accumulated Solids (Skalle et al. 2012).

Observation	Path strength	Explanation strength	Target error	Probability
Pack Off Took Weight Increased Drag Low ROP Low Mud Visc. Low Well Incl.	0.7*0.5=0.35 0.5 0.7 0.4*0.5=0.2 0.7*0.6=0.42 0.7	2,87	Accumulated Cuttings	2.87/4.67=0.62
Pack Off Took Weight Very Long Open Hole Time	0.4 0.6 0.8	1,8	Swelling Clay	1.8/4.67=0.38
Total		4,67		1

To know the failure cause is valuable. Correct diagnosis of the problem will lead to treatment that is appropriate and will result in efficient repair actions, leading to significant cost reductions.

3 General Knowledge of Cement Operations

Knowledge modeling is a combination of top-down and bottom-up approach; top-down is the model of initial textbook knowledge and bottom-up is what the model learns when new cases are solved (Aamodt 2004). This chapter will present initial knowledge about the cementing operation and the concepts involved in cementing failures, in order to make the reader understand the reasoning when constructing the DrillKM for cementing operations.

Renaming and simplification of the symbolic concepts is done before they can be used as input for the model. The description of the observation has to be short and specific, in order to make the problem easy to understand and to give the symbolic concept the ability to be stored and used for similar cases in the future (Skalle 2012). Each of the following subchapters will contain a short summary of all relevant concepts and their place in the ontology. The concepts mentioned will in Chapter 3.3 be gathered in to the ontology by organizing them into groups and subclasses of Parameter, Process, Error, Failure and Activity. This way of building the DrillKM is an example of top-down modeling.

3.1 The Cement Operation

Proper well cementing ensures safety. While the steel casing serves a primary shield against the ground water, specialized cement is used to create a pressure-tested seal between each layer of casing. In between each of these layers is a space that must be filled with cement to hold it in place, and to create a solid, sealed barrier against fluid inflow. Cementing is achieved by preparing the cement slurry and pumping it down the casing. As it is pumped down, the cement slurry displaces the mud already in the casing and passes out of the casing end and further up through the exterior of the casing, displacing the mud in front of it (Fig. 3.1). When all the mud has been displaced and the cement slurry thus is continuous around the outside of the casing, pumps are being stopped and the cement is allowed to set. The end of the casing includes a one-way valve which, when cementing is complete, prevents the cement to pass back up the casing.

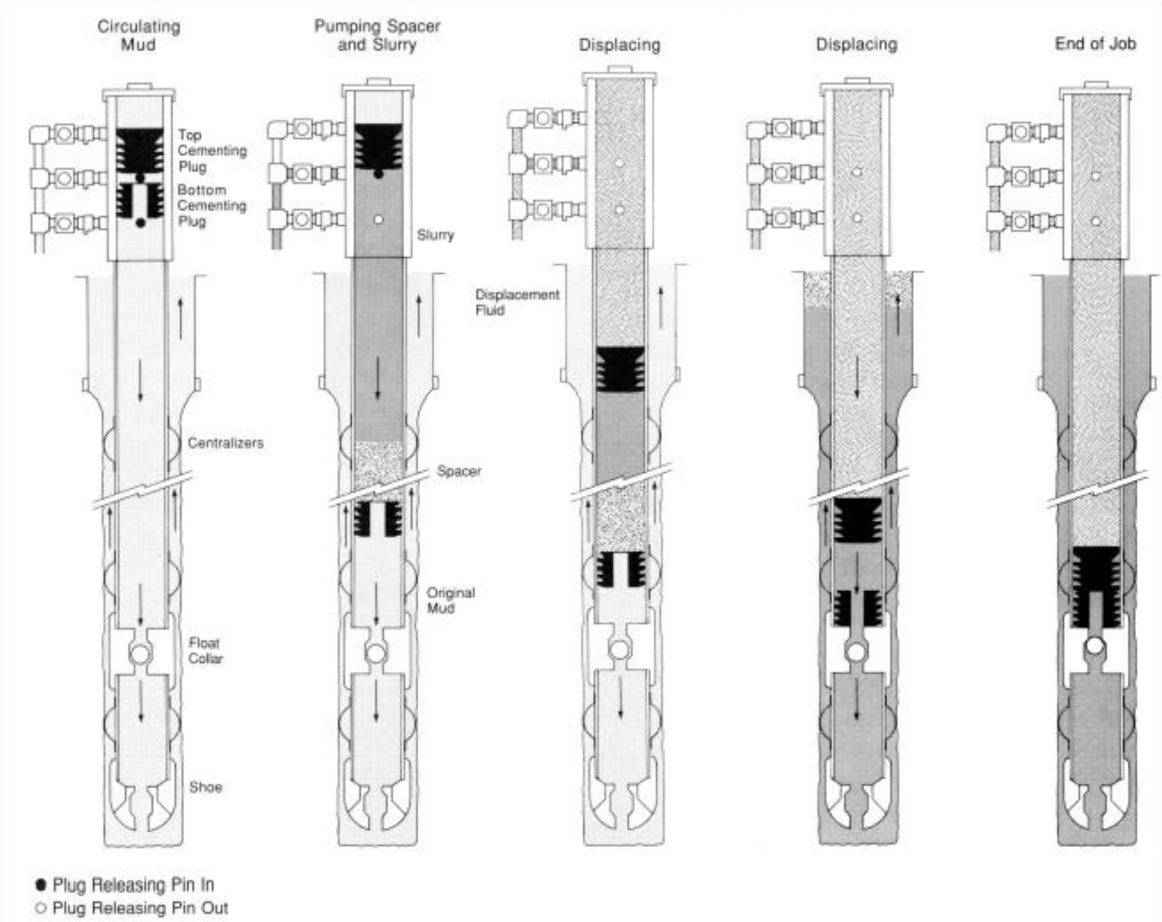


Fig. 3.1: Common one-stage primary cementing job on a surface casing string (Burdylo and Birch 1990).

This creates a seal preventing outside materials to enter the well flow, as well as it permanently positions the casing in place. Additionally, cementing is used to seal a lost circulation zone or areas where there is an absence or a reduction of the flow within the well. In directional drilling, cementing can also be used to plug an existing well in order to drill directional from that point. When plugging and abandoning a well, e.g. after a production operation have drained the reservoir, cement plugs are placed and pressure tested across the hydrocarbon-bearing formation, across the casing shoes, freshwater aquifers and perhaps several other areas near the surface of the wellbore.

In many instances the full production potential of a well may not be reached if complete zonal isolation is not achieved. Sufficient zonal isolation ensures that the environmental objectives in drilling the well are met. At the same time it is necessary to prevent fluid flow into the well, it is also important to prevent fluid channels in the cement sheath itself. If drilling fluid is not effectively displaced, if cement slurry is not placed in the entire annulus, and/or the cement sheath fails, a path for fluid migration could be created. The mentioned errors may occur because of shrinkage of the cement slurry and/or because of loss of structural integrity from its lack of capacity to withstand stresses from the well operation (Reddy 2007). These issues will be discussed more closely in the coming subchapters.

Related concepts in this subchapter	Position in the ontology
Cement Slurry Shrinkage	Parameter
Displacement Of Cement Slurry	Activity
Abnormal Cement Slurry Shrinkage	Parameter
Poor Stress Resistance in Cement	Parameter
Gas Migration	Process
Fractures In Cement Sheath	Parameter

3.1.1 Cement Stages

When displaced, the cement slurry transforms from a permeable liquid to a gel phase, and after some time it becomes an impermeable solid. To produce the cement slurry, water is mixed with cement powder in an exothermic reaction which can be observed as a temperature increase. Among other minerals, a needle like mineral called Ettringite forms out of each particle in the powder (Figure 3.2), and after a period of typically 3-6 hours the initial set stage is reached (Skalle 2012). The fluid like slurry begins to stiffen, as a result of the needle like particles starting to interfere with each other. At the final set the cement becomes hard and inpenetratable by a Vicat needle, an apparatus used to determine the setting time of cement by measuring the pressure of a special needle against the cement surface.

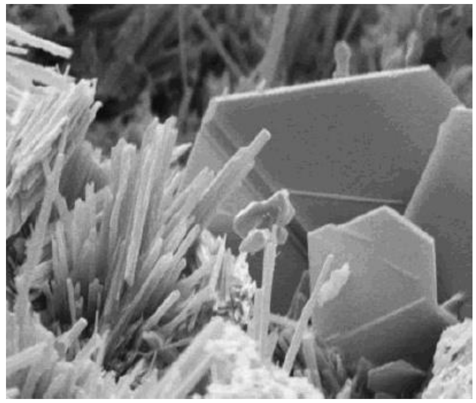


Fig. 3.2: SEM image of hardened cement, showing plates of calcium hydroxide and needles of Ettringite (micron scale), (Cementlab 2014).

The cement slurry loses its ability to transmit hydrostatic pressure during the transition from fluid cement slurry to hardened cement. As the slurry set, hydrostatic pressure is reduced on the formation. Gas bubbles increase in size as they travel up the annulus and during this transition. This gas may have left the reservoir and can travel through the cement column resulting in gas being present at the surface. The permeable channels, which gas flow, cause operational and safety problems at the well site.

Related concepts in this subchapter	**Position in the ontology**
Cement Hydration	Parameter
Too Fast Cement Hydration	Parameter
Too Slow Cement Hydration	Parameter
Channels In Cement Slurry	Parameter

3.1.2 Cement Design

The most common binding material in the well cementing process is Portland cement. Portland cement is also the most common example of hydraulic cement; a cement that set and develop compressive strength as a result of hydration. It involves chemical reactions between water and the compounds present in the cement, and the development is predictable, uniform and relatively rapid (Nelson 1990). The set cement has low permeability and is nearly insoluble in water. As a result of this, exposure to water does not destroy the hardened material. Such attributes is essential for a cement to achieve and maintain zonal isolation in the well.

The Portland cement is calibrated with additives to form one of the current eight phases of API Portland cement, designated A to H. Each of the classes is employed for various situations, like depths to which they are placed and the temperatures and pressures to which they are exposed. All additives will reduce the strength of the hardened cement. However, all the parameters, like permeability of the cement, are equally important parameters and need special attention with respect to e.g. gas migration resistance.

As a primary requirement, slurry density must be correctly designed to prevent gas flow during cement placement. There is a danger of losing circulation or fracturing an interval if mud densities are too high. Considerations must also be given to the "Free-fall" or "U-tubing" phenomenon that can occur during cement jobs. These issues happens when the weight of the slurry causes it to fall faster that it is pumped, and will be discussed more closely in Chapter 3.2.

When designing displacement rates and pumping schedules these phenomenon must be considered, and cement jobs should therefore be designed using a placement computer simulator program to assure that the pressure at critical zones remains between the pore and fracture pressure during and immediately after the cement job (Schlumberger 1996).

Density errors made while mixing a slurry on the surface may induce large changes in critical slurry properties, such as rheology and setting time. Inconsistent mixing also results in placement of a non-uniform cement column in the annulus that may lead to solids settling, free-water development or premature bridging in some parts of the annulus.

Revealed concepts in this subchapter	**Position in the ontology**
Too High Mud Weight	Parameter
Too Low Mud Weight	Parameter
Fractures In Cement Sheath	Parameter
U-Tubing	Error
Non-Uniform Cement Column	Parameter
Solids Settling	Parameter

Water Channel in Cement	Parameter
Lost Circulation	Failure

3.1.3 Displacement Process

Since the casing walls have non-slip conditions, the velocity profile of the cement being pumped into the well will become distorted if we assume a purely laminar flow. Displacement of the mud by cement will lead to some amount of leftover mud along the wall, especially in the upper parts of the displaced wellbore (Skalle, 2014). The cement quality will drop due to mud occupying an increasing share of the well (Fig. 3.3), which may lead to reduced cement bonding to the wellbore wall and/or to contamination by mud in the slurry. The phenomenon is known as axial dispersion of the cement slurry.

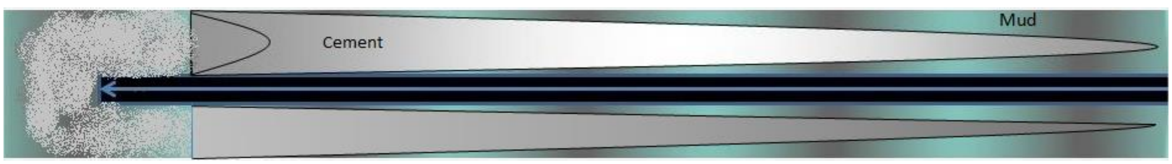


Fig. 3.3: Cement being displaced to the left. The initial velocity profile to the left and resulting profile towards right.

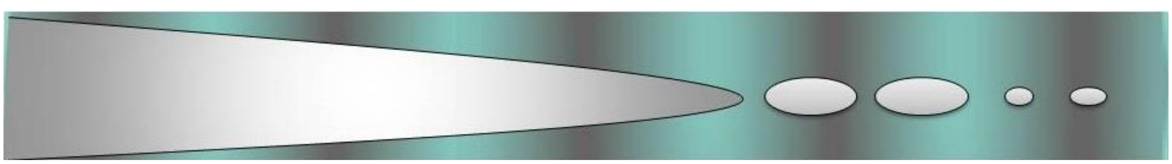


Fig. 3.4: Very low cement quality. The cement forms "bubbles" further out in the velocity profile.

In reality the problem does not necessarily end up as poor as Fig.3.3 and Fig.3.4 demonstrates. The walls in the well are normally not completely smooth, and the cement "sticks" better to the walls and slows down the process.

Axial dispersion of the cement slurry occurs when the average slurry velocity becomes higher in some parts of the annulus. The phenomenon is typical in high inclination wells where the risk of obtaining a poor centralized casing is greater. The reduced flow in the activated area between the casing and the wellbore wall causes the cement slurry to flow faster through other parts of the annulus and thus higher annular dispersion (Fig. 3.5). In shallow gas bearing formations axial dispersion of the cement slurry can lead to dangerous situations, because the cement quality well be poor where you need good cement the most.

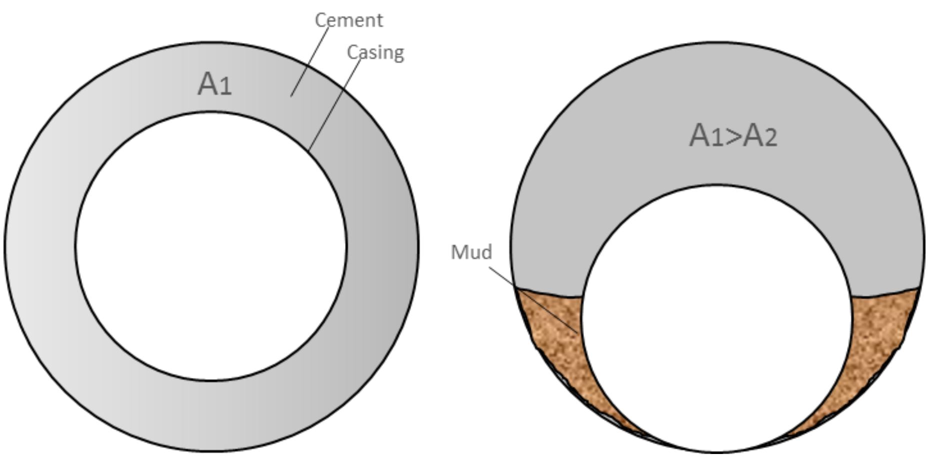


Fig. 3.5: Ideally displaced cement slurry (left) and slurry displaced in a well with poor centralized casing (right). The area of the flowing cement slurry (A1) will occupy a larger amount of the annulus than the still standing mud (A2), and thus flow with a higher average velocity.

Revealed concepts in this subchapter	**Belongs where in the ontology**
Shallow Gas Bearing Formation	Parameter
Cement Bubbles Creation	Parameter
Axial Dispersion Of Cement Slurry	Parameter
Poor Centralized Casing	Parameter
High Well Inclination	Parameter
Lower Annular Flow In Activated Area	Parameter
High Average Slurry Velocity	Parameter
Mud Contaminated Cement	Parameter
Poor Cement Bond	Parameter

3.2 Cement Failure Mechanisms

The next sections are based on textbook knowledge and present possible errors and failures during the cementing operation. The concepts presented here will also be embedded into the DrillKM in Chapter 3.3.

3.2.1 Leaking Annulus

An annulus leak is defined as an escape of reservoir or injection fluids through the completion and casing tubular of the well (Abdollahi 2008). The occurrence of the well leaks with respect to the start of production or injection is important for the analysis of causal connections.

- Early leaks refer to leaks occurring within 3 months of installation (drilling and completion phase).
- Late leaks refer to leaks which occur after 3 months of installation.

A study of 18 cases on the Norwegian Continental Shelf (NCS) (Abdollahi et al. 2008) showed that most of the injection wells studied were reported leaking in the early phase of operation. Most of the production wells using gas lift systems were reported leaking in the later phases of the operation. Injector wells were exposed to large temperature and pressure changes in the beginning of the operation, leading to extra loads on the strings and connections which resulted in leakages. The injections wells did most likely suffer from thermal and pressure loads in the beginning of the operation phase, which resulted in weakening of the cement and thereby the leaks.

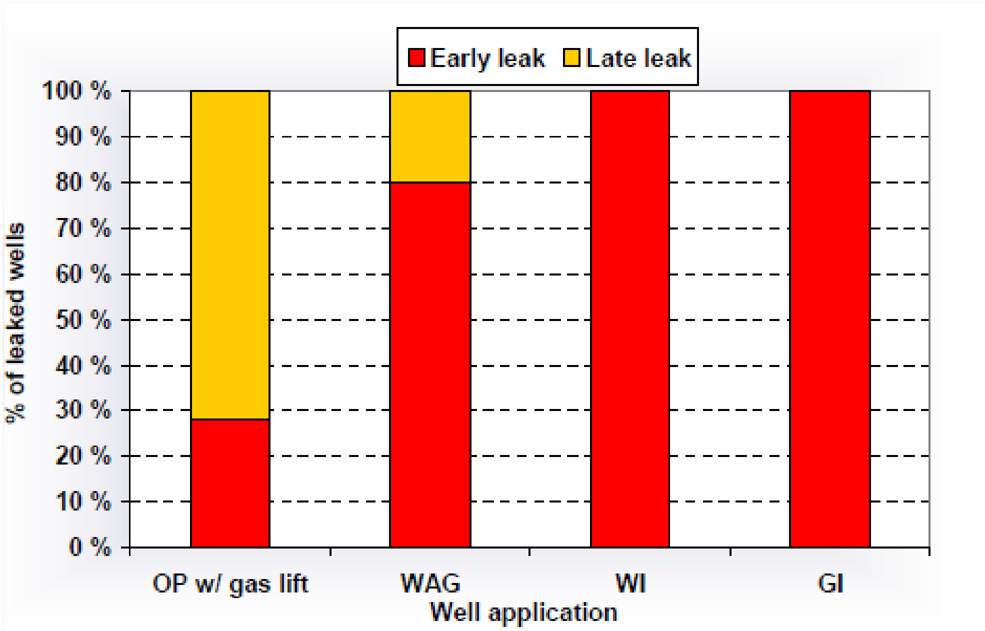


Fig. 3.6: Early and late leaks for different well applications for three NCS fields (Abdollahi 2008).

A cement job of high quality will decrease the chance of late leaks and increase the chance of reusing old casing strings in slot recovery operations. Fig. 3.7 indicates that cement failures is one of the greatest challenges regarding well integrity on the NCS (Vignes 2011). 11% of the total number of wells with issues in a survey based on well integrity information from seven operating companies, 12 offshore facilities and 406 wells had problems with the cement barrier at one point of the wells life cycle.

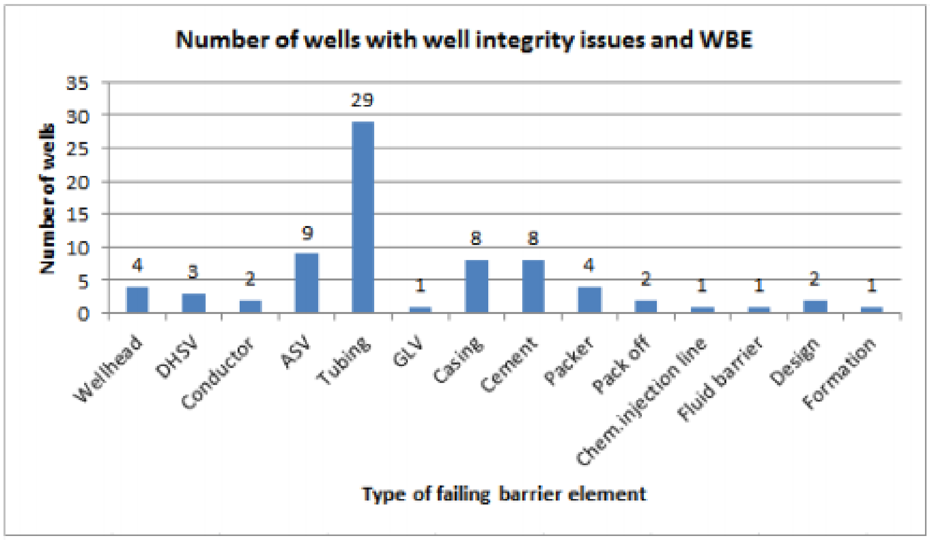


Fig. 3.7: Illustration of in which well barrier element (WBE) the wells with integrity issues experience problems on the NCF (Vignes, 2011).

Related concepts in this subchapter	**Position in the ontology**
Wellbore Pressure Fluctuation	Parameter
Wellbore Temperature Fluctuation	Parameter
Injecting Water	Activity
Gas Lift	Activity
Annular Leak	Error
Early Annular Leak	Error
Late Annular Leak	Error
Weakening Of Cement	Parameter

3.2.2 Gas Migration

Gas migration goes by many names; gas communication, gas leakage, annular gas flow, gas channeling, flow after cementing or gas invasion (Nelson 1990). It is a potential problem in almost all gas-bearing or gas storage wells, and the severity ranges from the most marginal, e.g. a residual gas pressure of a few psi at the wellhead, to the most hazardous e.g. a blowout situation where the well control is lost because of severe pressure imbalance during drilling or cementing. Less easily detected is the downhole interzonal communication. It materializes as invasion of formation gas into the annulus, partly because of a pressure imbalance at the formation face. Gas migration can also occur even when the annular fluid densities are such that the initial hydrostatic head is much higher than the gas pressure.

It is generally acknowledged in the industry that the mechanism that allows gas invasion into the cement matrix is the gel-strength developed of the slurry as it changes from liquid to solid. In this condition the cement loses its ability to transmit the hydrostatic pressure, and invasion of gas may occur. Other mechanisms include excessive fluid loss, bridging and the formation of microannuli.

Without proper slurry design, natural gas can invade and flow through the cement matrix during the Wait on Cement (WOC) time. Failure to prevent this gas from invading the cement can cause such problems as high annular pressure at the surface, blowouts, poor zonal isolation, loss of gas to nonproductive zones, poor stimulation of reservoir and low producing rates of hydrocarbons. All of these events are costly to correct.

Gas migration may occur during drilling or well completion operations. Inadequate sealing of varying formations in the wellbore can lead to the migration of gas. The migration occurs through the invasion of formation fluids into the annulus and is caused by a pressure imbalance in the formation face. The fluids can flow to a lower pressure zone and, in some cases, to the surface.

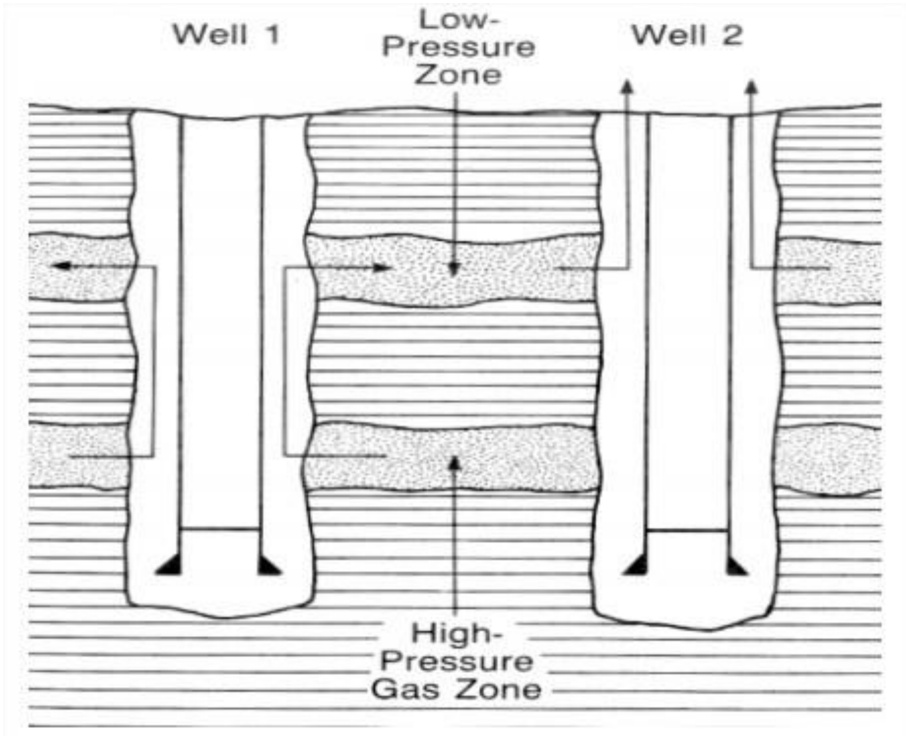


Fig. 3.8: Mechanism for annular gas migration (Parcevaux et al. 1990).

Fluid migration from high pressure zones to those of lower pressure can lead to contamination of these zones. Extreme gas accumulation due to large pressure imbalances can cause blowouts.

The severity of gas migration is not always apparent. Gas migration after primary cementing can adversely affect the wellbore and evidence may only be noticed some time after. Remedial cementing procedures are thus required to correct such problems.

Gas migration between zones, which does not build up at the surface is, as mentioned, difficult to detect and may cause problems like (Sutton et al. 1989):

- Impaired gas production
- Filling of the above depleted zones
- Reduced effectiveness of stimulation treatments

When the gas migration problem was first recognized it was thought that it resulted from poor mud removal properties. As has been seen, poor mud removal does not allow for adequate bonding at the cement/casing/formation interfaces. This can lead to the development of channels for fluid migration. Although other causes of fluid migration have been recognized, the principal cause stems from a mud removal problem. This is due to the continuous mud channels in the annulus between two permeable zones favoring annular flow.

As mentioned in Chapter 3.1 the cement slurry behaves as a fluid and transmits hydrostatic pressure immediately after placement. A compensation of volumetric changes due to hydration and fluid loss is accomplished by a reduction in the height of the cement column. Continued fluid loss from the slurry, as well as hydration, results in the development of a gas structure that can cause the cement to lose its ability to transmit fluid pressure. At this stage it is possible for the pressure to drop and become less than the gas pressure, as Fig. 3.9 demonstrates. A potential for gas flow now exists. During this stage the cement becomes self-supporting and further hydration causes a further decrease in pressure. The gel structure restricts pressure as cement slurry thickens with time. Gas flow can be inhibited by the formation of strong bonds between cement particles which reduces permeability. The critical area is indicated by the shaded region in Fig. 3.9.

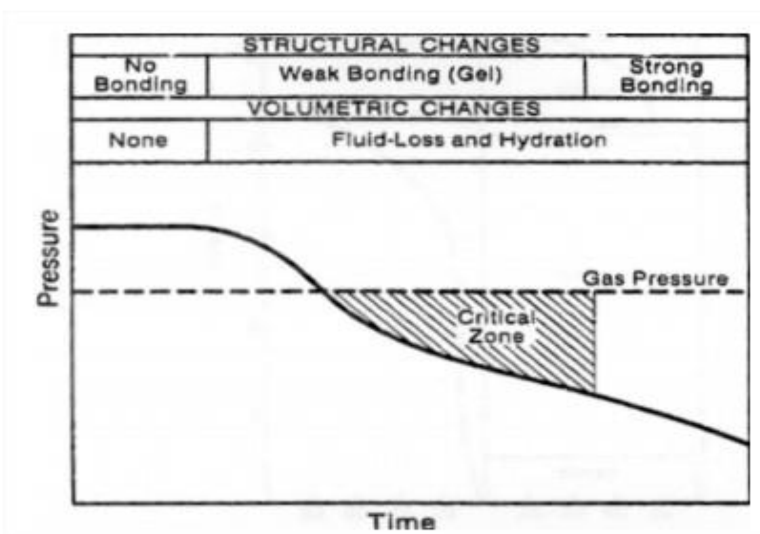


Fig. 3.9: Slurry dynamics immediately after placement. Critical area is indicated by the shaded region (Bannister et al. 1983).

The formation gas can flow up to the surface through many different routes (Coker et al., 1992):

- Along the formation/cement interface
- Along the casing/cement interface
- Through unset cement by percolation of gas bubbles
- Through the microstructure of unset cement
- Through channels in unset cement
- Through unset cement in underbalanced “blowout” conditions
- Through cracks, channels, or permeability in set cement
- Through any combination of the above

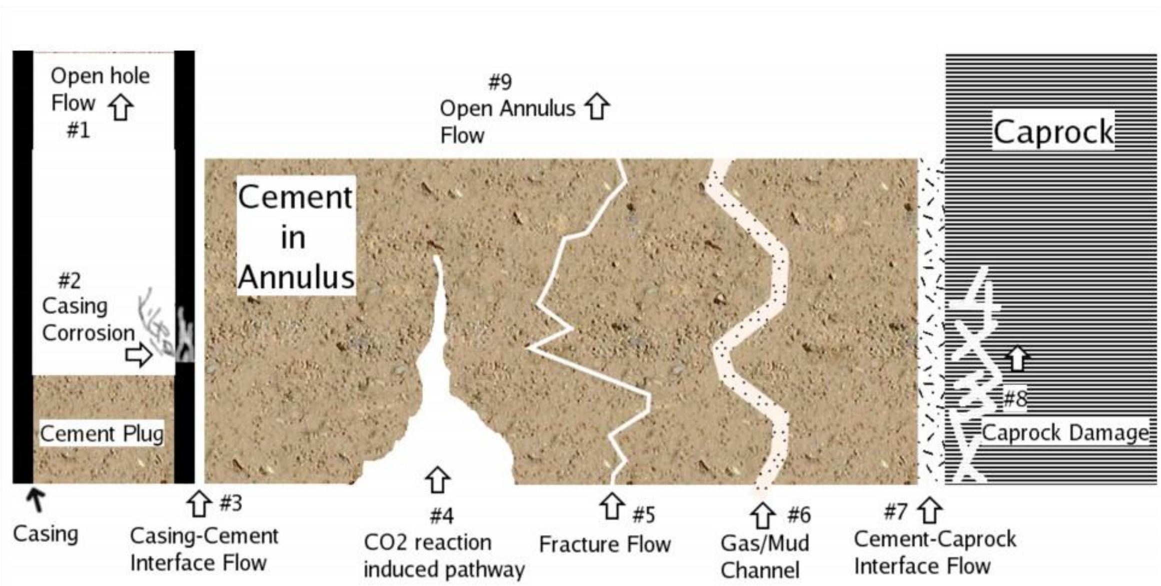


Fig. 3.10: Different migration routes and failure modes of cement (Carey 2010).

Through the Cement Pore Structure

Gas percolation can be considered as a particular type of gas migration, where gas in the form of microscopic bubbles invades the slurry, and rise due to buoyancy effects in accordance to Stoke’s law.

Poor fluid-loss control in front of a gas bearing zone accelerates the decrease of cement pore structure. Fluid loss occurring higher up in the hole hinders transmission of hydrostatic head from the column above the invasion point to the bottom of the hole. Gas migration may thus find its way through the pore structure of very permeable gelled or set cement, as well as the potential of gas percolation beforehand within the gelling slurry.

Along Weak Bonds

Gas can migrate along the cement/formation or cement/casing interface regardless of the cement system. If micro annuli have developed or if any weakness appear where the bond strength is reduced, paths can be created where the gas can migrate. Good bonding is the principal goal of primary cementing, and the potential causes for a bonding defect are many:

- Lack of roughness along the surface of the casing and formation
- Cement bulk volumetric shrinkage
- Mud film or mud channel forming at the interface
- Free-water channel or layer in deviated wells
- Excessive downhole hydraulic stresses
- Excessive downhole mechanical stresses

Cement shrinkage itself probably does not lead to development of a microannulus, but instead to the development of reduced surface bond. Thus, the development of a true microannulus could only be due to an additional stress imbalance between one of the two considered interfaces (Skalle 2012).

After Cement Setting

After setting, during the hardening phase, normal density cement becomes a solid of very low permeability at the micro Darcy level. However, it should be noted that low-density systems with high water-to-cement ratios can exhibit fairly high permeabilities (0.5 to 5.0 mD). Therefore, it is possible for gas to flow, albeit at low rates, within the matrix of such cement, and to eventually reach the surface. Such events may take weeks or months to manifest themselves as measurable phenomena at the surface, where they usually appear as slow pressure buildups in the shut-in annulus (Skalle 2012).

Revealed concepts in this subchapter	Position in the ontology
High Annular Surface Pressure	Parameter
Slow Pressure Buildup In Shut In Annulus	Parameter
Gas Leak At Wellhead	Error
Long WOC Time	Parameter
Low HC Production Rate	Parameter
Impaired Gas Production	Parameter
Gas Percolate To Upper Depleted Zones	Process
Mud Cake	Material
Excess Downhole Hydraulic Stresses	Parameter
Excess Downhole Mechanical Stresses	Parameter
Poor Mud Removal	Parameter
Blowout	Failure
Cement Corrosion	Parameter
Corrosive Agents In Well	Parameter

3.2.3 Microannular Formation in Cement

It is possible that a microannulus can be formed between either the casing and the cement or the cement and the formation. Such occurrences can be determined through the use of a cement bond log response or through the observation of gas migration problems.

One example of microannulus formation is given in terms of the radial displacement of the casing resulting from wellbore temperature and/or pressure changes. This occurs predominantly when the wellbore pressure is decreased, i.e. a change in mud weight when the cement has set. This type of microannulus is known as an inner microannulus. An outer microannulus is formed when there is cement bulk shrinkage (Mavroudis 2001). This is a worst-case scenario, but a realistic one. A clear understanding of these mechanisms is essential to identify extreme cementing problems in some cases, and to build the correct ontology.

The use of expanding cements can help to prevent the formation of microannulus. Theoretically, expanding cement will fill any gap and will ensure that good bonding is achieved between either the casing and the cement or the cement and the formation.

Expanding cement is known to move only in the direction of the formation and not in the direction of the casing.

Revealed concepts in this subchapter	**Position in the ontology**
Cement Slurry Shrinkage	Parameter
Microannulus Between Casing and Cement	Parameter
Microannulus Between Cement and Formation	Parameter

3.2.4 Shrinkage

Annular gas flow may be initiated when the hydrostatic pressure of the cement declines and falls below the pressure of a gas bearing formation due to the combined effect of shrinkage, fluid loss to the porous well and the gel strength build up. A low shrinkage is preferable because the resulting hydrostatic pressure decline will be lower for a slurry with low shrinkage than for a slurry with high shrinkage, i.e. pressure equilibrium between gas and slurry column is reached at a later point of time.

The chemical shrinkage may be divided into two parts; external and internal shrinkage. The external shrinkage expresses the bulk volume change of the slurry (Lyomov 1998). The volume of the products formed is less than the volume occupied by the reactants (i.e. cement powder and water), and can lead to a possible microannulus between the cement and the borehole wall. The internal chemical shrinkage is the shrinkage caused by formation of contraction pores which contribute to the connectivity between pores in a set cement, and hence, to permeability.

Tests carried out by Chenevert and Shrestha, and by Sabins and Sutton (1991) shows that both total and external shrinkage at 20 to 24 hours varies from 0.6 to 6.0 vol. %, while most results were in the range of 1.5 to 3.0 vol. %. According to Sabins and Sutton most external shrinkage occurs when the slurry still is in the plastic phase. Their results showed an average shrinkage of 0.15 vol. % and they calculated the contraction pores to account for 97.5 to 99 % of the total shrinkage. Thus, from a gas migration point of view, the formation of contraction pores is by far the largest and most important part of the chemical shrinkage.

3.2.5 Water Loss

When determining the placement characteristics of cement, water loss considerations are essential. Before the cement slurry sets, interstitial water is mobile. Therefore, some degree of fluid loss always occurs when the annular hydrostatic pressure exceeds the formation pressure. The process slows down when a low permeability filter cake forms against the formation wall, or can stop completely when annular and formation pressures equilibrate. Once equilibrium is reached, any volume change within the cement will cause a sharp pore pressure decline in the cement slurry or the developing matrix, and severe gas influx may be induced (Schlumberger 2009). Equally important is it to have a cement slurry with low or zero free water, particularly in deviated wells. As cement particles settle to the low side, a continuous water channel may be formed on the upper side of the hole, creating a path for gas to migrate, as demonstrated in Fig. 3.11.

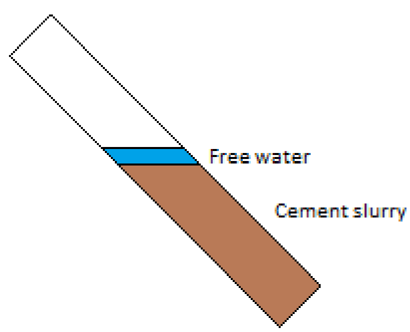


Fig. 3.11: Schematic diagram showing fully developed water channeling (Skalle 2012).

Under the static conditions following the cement placement, uncontrolled fluid loss from the cement slurry into the formation contributes to volume reduction. This reduces pressure within the cement column and allows space for gas to enter. If filtrate invades a formation then formation damage is also likely to occur. Additionally, water loss can disturb the hydration process in the cement, and in worse case prevent complete hydration. This typically leads to weak cement and poor cement-formation bond. For a drilling operator it is essentially to be able to calculate and control the water loss.

Revealed concepts in this subchapter	Position in the ontology
Cement Hydration Prevention	Parameter
Water Loss In Cement Slurry	Parameter
Hydrostatic Pressure Loss In Cement Slurry	Parameter
High Water Loss In Cement Slurry	Parameter
Uncontrolled Fluid Loss From Cement Slurry	Parameter
Erosion Of Weak Formation	Parameter

3.2.1 U-Tubing

Because the cement slurry density is greater than the density of the mud being displaced, the forces resisting the flow of cement are insufficient to allow the pumping pressure to be maintained. The result can be a cement slurry falling faster than the pumping rate under the effect of gravity, and obviously not longer under the control of the pump (Nelson 1990).

This is undesirable because the increased flow rates during “U-tubing” can cause strongly turbulent flows which can erode any weak formation around the casing seriously and cause laminar flow while equilibrium is being sought. The phenomenon can also result in creation of vacuum behind the “U-tubing” cement slurry which then may then halt the slurry and make the pump being filled with vacuum and stop. Surging can also be a result of the “U-tubing” phenomenon. It may even occur in such a rate that the mud is forced to the surface where it can be hard to control without causing unfavorable pressure increases downhole.

Revealed concepts in this subchapter	Position in the ontology
Turbulent Cement Slurry Displacement	Parameter
Unintentional Stop Of Cement Displacement	Parameter
Pressure Surging	Parameter
Eroding Of Weak Formation	Parameter
Cement Pump Failure	Failure
Kick	Error and Failure

3.2.2 Cyclic Fatigue

New well applications in the oilfield industry might expose well completions to cyclic loading. The casing and cement compound in geothermal wells or steam injection wells can be exposed to high temperature changes. These changes can be cyclic for operations, using one well solutions, where injection of cold and production of hot water is performed through one well. This saves the costs of the construction of one or event two wells compared to the classical solution with one production and one injection well. In addition steam injection is for some instances not applied continuously, but as a cyclic measure for enhanced oil recovery.

The cyclic fatigue phenomenon also happens while working on a well without stem injection. While drilling the well the temperature rises. During breaks in the drilling process the temperature falls again. This heating and cooling process leads to expansion and shrinkage of all materials in all scenarios in the well. Especially the casing is affected from temperature changes, as metals provide very high thermal expansion coefficients. Thermal expansion induces forces in the cement sheath, which might lead to a cement failure.

Long-term effects in the cement integrity occur due to the change in temperature and down-hole pressure during production of a well. The factors act as stress generators within the cement. If the set cement is exposed to more stress than it is designed to manage, the results could be fissures in the cement, debonding of cement from the formation or creation of a microannuli between the casing and the cement. Studies carried out by Goodwin and Crook in 1992 showed that when the cement was exposed to an increase in stress by casing expansion, the result was that the cement failed in the lower parts of the string. When the temperature difference was even more significant in the upper parts of the well, where tensile cracks were formed. An increase in the temperature leads to expansion of the casing outwards, and this expansion was proved to generate tensile stresses in the cement. The effect on the casing caused by temperature alternation is demonstrated in Fig. 3.12.

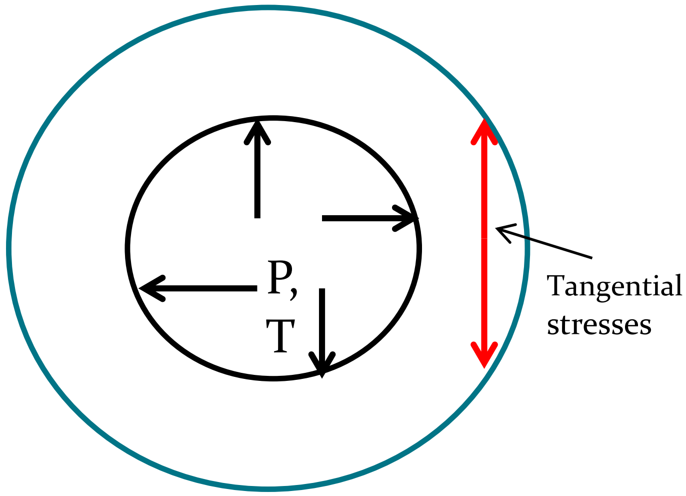


Fig. 3.12: Stresses on the cement when the casing is expanding (Goodwin and Crook 1992).

Casing contraction occurs when the pressure in the wellbore decrease. This will cause the casing to pull away from the cement, and that may cause debonding between the casing and the cement. If this debonding happens, there will be created a microannuli which makes way for fluids to migrate up the borehole on the outside of the casing, and thus cause an annular leak.

To avoid failure of set cement, it is important to design cement systems that provide a proper well integrity throughout the life time of the well. In order to achieve this, the expected down-hole pressures and temperatures during production must be thoroughly calculated. By having knowledge of the type of fluids which will be run in the well, there can be done accurate simulations of the change in down-hole pressures and temperatures. To know the changes in the down-hole pressures which may arise during the lifetime of the well, it is possible to perform computer-aided stress analysis to calculate what effect this will have on the cement sheath. These simulations may help to identify the most suitable sealant system that can last throughout the lifetime of the well (Goodwin and Crook 1992).

Revealed Concepts in this subchapter	**Position in the ontology**
Injecting Steam	Activity
Casing Expansion	Parameter
Casing Contraction	Parameter
Fractures in Cement	Parameter

Fractures in Cement	Parameter
Cyclic Casing Expansion/Contraction	Parameter
Mechanical Stress On Hard Cement	Parameter

3.2.3 Mud Cake Removal for Cementing Job

A complete displacement of the cement must be achieved in order to cement successfully. If channels of mud remain in the annulus, the lower yield stresses of drilling fluid may offer a preferential route for gas to migrate. Furthermore, water may be drawn from the mud channels when they come into contact with the cement. This can lead to shrinkage-induced cracking of the mud, which also provides a route for gas to flow. If the mud filter cake dehydrates after the cement sets, a microannulus may form at the formation-cement interface, thus providing another path for gas migration. For example, a 2.0 mm thick mud filter cake contracting by 5.0 % will leave a void 0.1 mm wide that has a "permeability" in the order of several Darcies (Schlumberger 1996).

There are many existing methods of mud removal:

- Cement Pre-flushers
- Centralizing of casing
- Casing movement
- Conditioning of the drilling mud

In case of improper centralization of the casing, the cement might not fully displace the mud from the annulus during the cementing operation. The cement rather flows in the wide opening of the well than in a narrow opening. This result in cement eccentricity and non-uniform cement thickness.

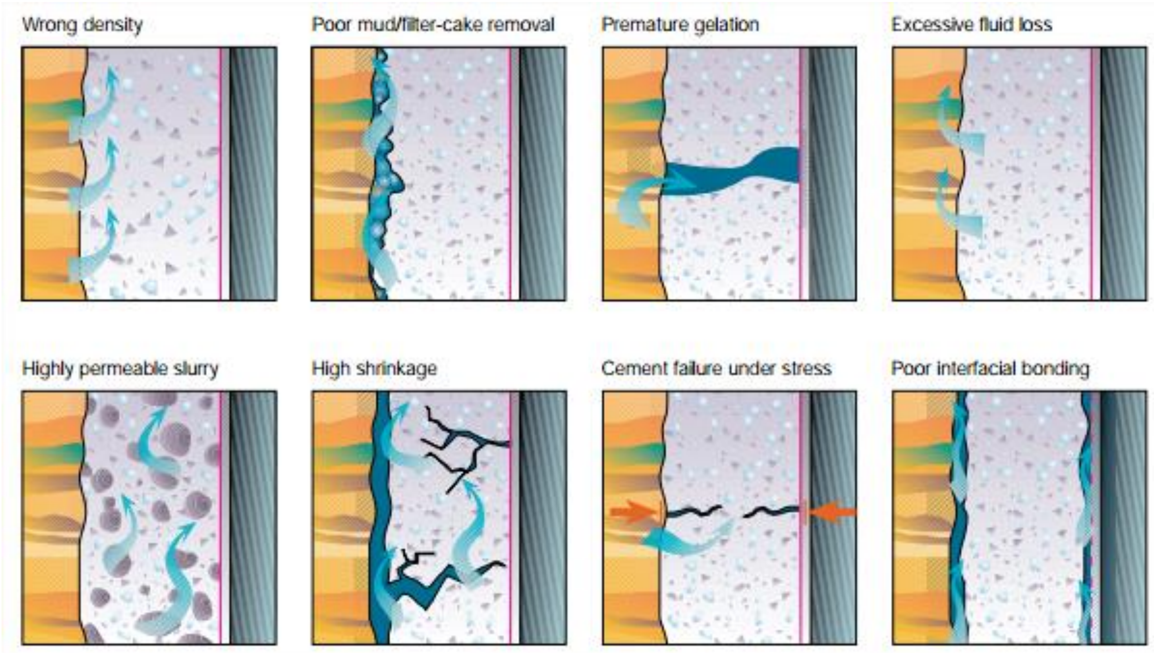


Fig. 3.13: The major parameters contributing to cement failure, in the order that they typically occur (Schlumberger 1996).

Leaks through the cement sheath can in other words occur through many different ways. Incorrect cement densities can result in a hydrostatic imbalance. Poor mud and filter-cake removal leaves a route for gas to flow up the annulus. Premature gelation leads to loss of hydrostatic pressure control. Excessive fluid loss contributes to available space in the cement slurry column for gas to enter. Highly permeable slurries result in poor zonal isolation and offer little resistance to gas flow. High cement shrinkage leads to increased porosity and stresses in the cement sheath that may cause a microannulus to form. Cement failure under stress helps gas to fracture cement sheaths. Poor bonding can cause failure at cement-casing or cement-formation interfaces (Schlumberger 1996).

Revealed concepts in this subchapter	**Position in the ontology**
Mud Cake Dehydration	Parameter
Premature Cement Slurry Gelation	Parameter
Non-Uniform Cement Column	Parameter
Poor Centralized Casing	Parameter

3.3 Knowledge Models of Cement Issues Based on Textbook Knowledge

All the revealed concepts through the previous subchapters will now be implemented to the DrillKM. Fig. 3.14 demonstrates how all mentioned parameters, activities and processes are structured into the ontology in accordance to where they take place. As an example, the subclass Parameter is subdivided into all possible subclasses of where the parameters occur; in the wellbore wall, equipment or the wellbore itself, during the drilling operation or the production phase. These subclasses are further subdivided into other subclasses in order to make it easy to find a concept and to make it all more structured and logic. The current revealed Parameters are all embedded into one of the mentioned subclasses of Parameter.

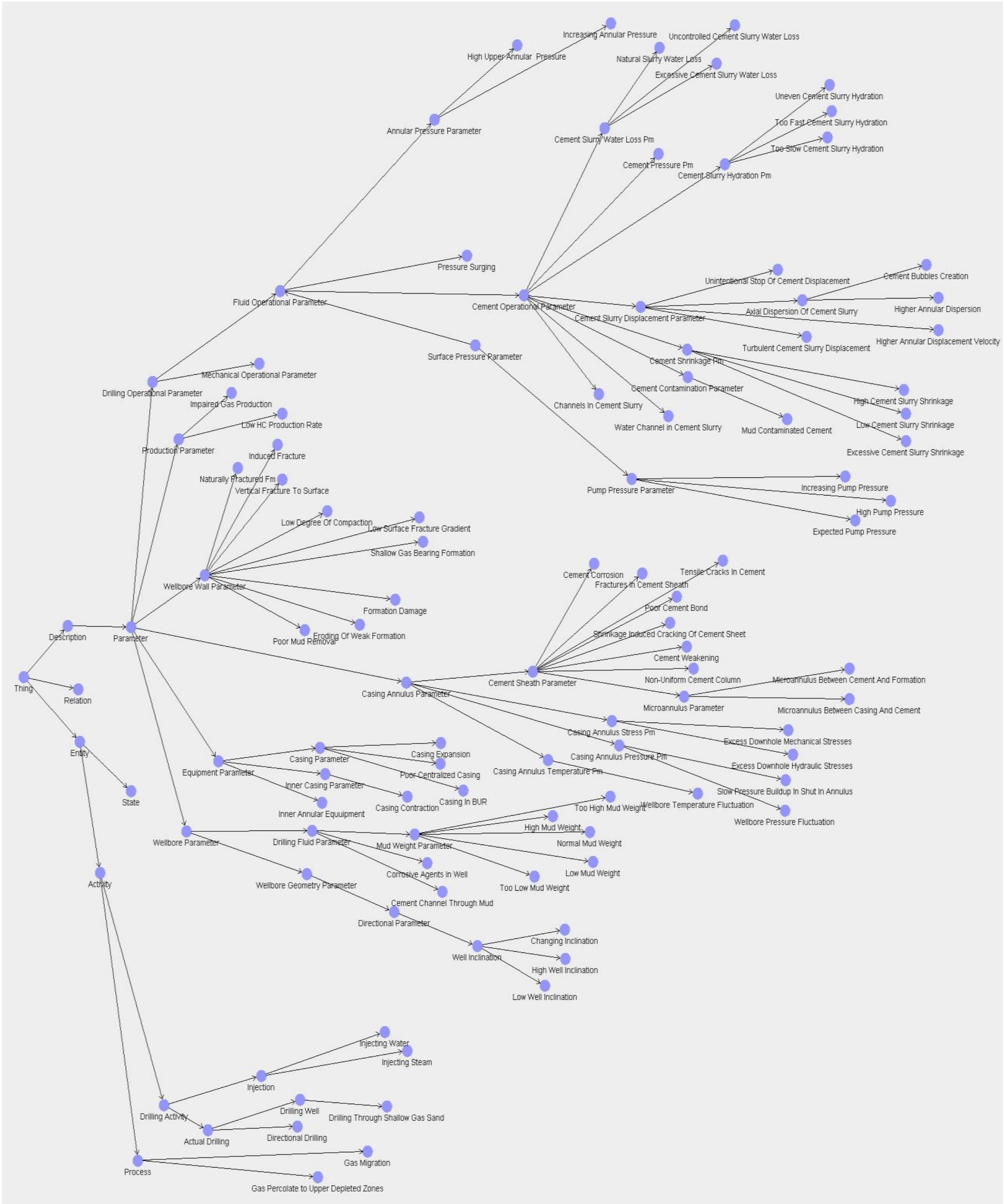


Fig. 3.14: All parameters revealed in Chapter 3 are here modeled in a subclass structural hierarchy.

Fig. 3.15 demonstrates all the errors and failures structured into the ontology. They are, as for the Parameters, structured according to where the errors or failures takes place.

New concepts revealed through the case observations in Chapter 5 will later be embedded into the same structure. This approach of organize and transfer experience will describe a problem in a purposeful manner.

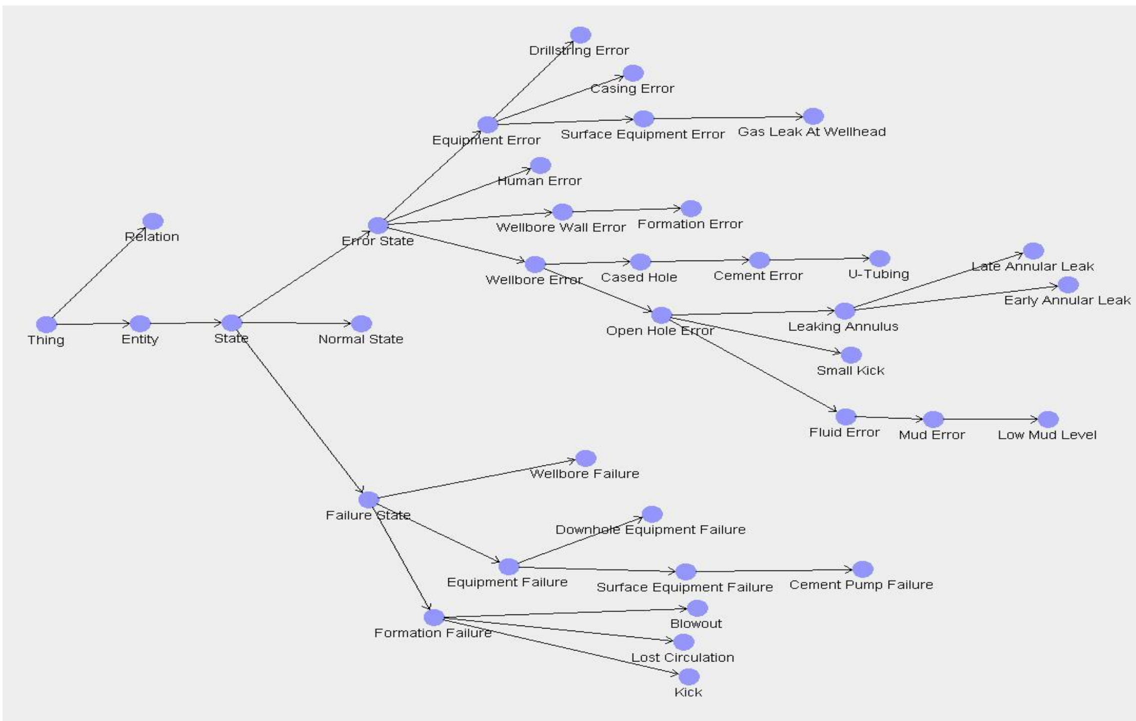


Fig. 3.15: Subclass structure of all cementing related errors, failures and activities revealed in Chapter 2.

Table 6 presents a few relationships from the concept Gas Migration presented in Chapter 3.2 for purpose of exemplifying how the concepts in the DrillKM are related to each other. The full overview of all concepts and relations are presented in Appendix A.

Table 6: Section of the DrillKM, here exemplified by Gas Migration.

Concept		Relation		Strength		Target concept
Gas Migration		causes		0.7		High Annular Pressure At Surface
Gas Migration		causes		0.7		Uncontrolled Flow In Cemented Annulus
Gas Migration		causes		0.7		Increasing Annular Pressure
Gas Migration		causes		0.7		Kick
Gas Migration		caused by		0.7		Hydrostatic Pressure Loss In Cement Slurry
Gas Migration		caused by		0.7		Fractures In Cement Sheet
Gas Migration		caused by		0.7		Poor Cement Bond
Gas Migration		caused by		0.7		Cement Channels Through Mud
Gas Migration		caused by		0.7		Poor Cement Quality
Gas Migration		caused by		0.7		Microannulus
Gas Migration		caused by		0.7		Water Channel In Cement Slurry
Gas Migration		caused by		0.7		Channel In Cement Slurry
Gas Migration		caused by		0.7		Tensile Cracks In Cement

4 Cases of Leaks through the Cement

In this chapter we will learn more specific knowledge regarding cementing problems. The five incidents presented here will give us a bottom-up approach in further building the DrillKM.

The model will thereafter be tested in Chapter 5.4 and Chapter 6, to respectively find the most probable failure and failure causes.

4.1 Presentation of cases

Investigation reports from Minerals Management Service (MMS) and Statoil are used to demonstrate how the information from within the failure is used to further build the Knowledge Model, and how the Knowledge Model can be used to detect the cause of an incident.

Each incident will be presented separately together with all new concepts. Later, all new concepts will be implemented in the DrillKM.

4.1.1 The Well C-7 ST, Grand Isle Block 90 Incident

The Well C-7 ST, Grand Isle Block 90 Incident, from now on referred to as Case 1, consisted of a surface and subsurface loss of control of shallow natural gas during surface casing cementing operations. The loss of control precipitated a rig evacuation. No pollution, injuries or damage resulted from the incident.

Brief Description, Loss of Well Control

In November 2002, the Diamond Offshore Drilling Inc. jack-up rig Ocean King was engaged in drilling operation for BP Exploration & Production Inc. on Grand Isle Block 90 Well C-7 sidetrack. Drilling operations were being conducted with the rig cantilevered over the platform using the re-claimed slot of the C-7 well, which earlier had been plugged and abandoned.

The surface location for Well C-7 ST covers approximately 5000 acres and is located in Grand Isle Block 93, Gulf of Mexico, offshore, Louisiana. The 13th of November 2002 the rig was conducting directional drilling operations. At the 14th of November 2002 at approximately 02.30 hrs. gas and some fluid flow from the surface/conductor casing were detected at the Well C-7 ST (side track).

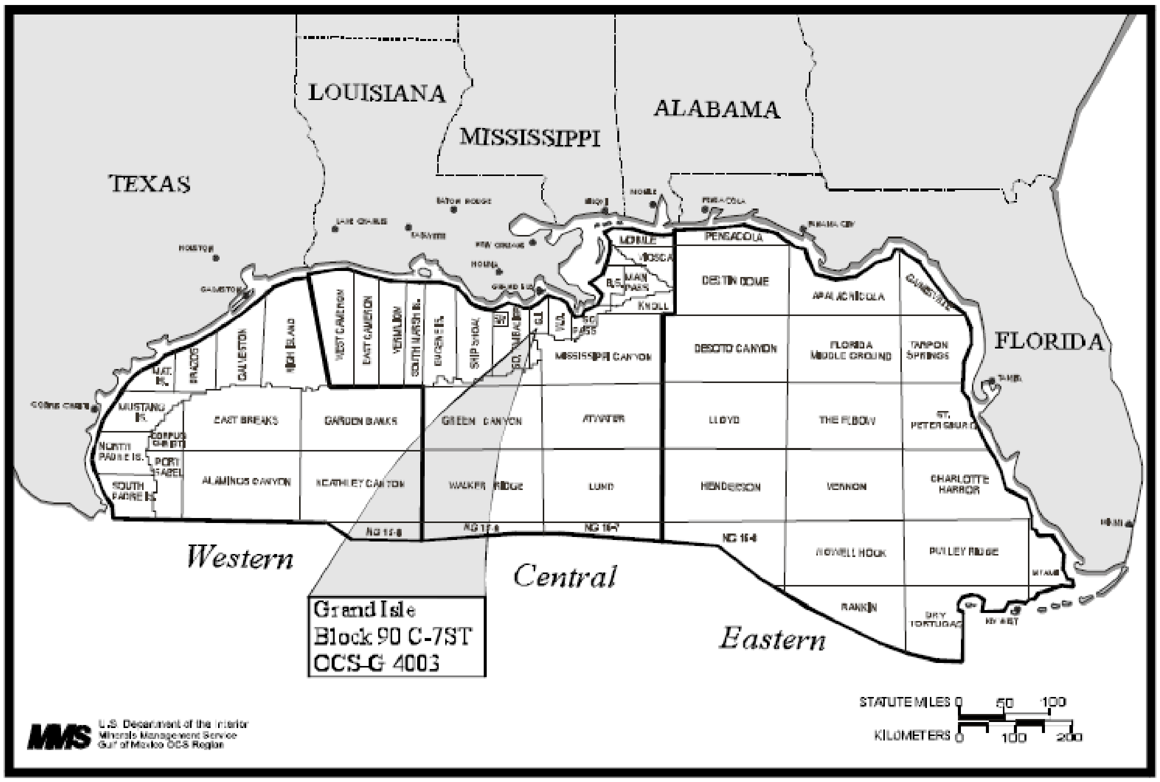


Fig. 5.1: Location of Lease OCS-G 4003, Grand Isle Block 90 (MMS, 2003)

At 23.00 hrs, 13 November 2002, the surface casing was run to approximately 5150 ft. and cemented to surface. When the leak occurred, the diverter sealing packer element (diverter packer) and diverter vent line valves were shut by placing the diverter system into "test" mode, in an attempt to hold the backpressure and allowing the cement to cure.

Pressure on the annulus then built to 580 psi. As the pressure mounted, intermittent leaking of gas past the diverter flowline seals were observed and heard to be increasing. Because of uncertainty of the cause of the leak, confusion about the integrity of the diverter seals, and the fact that the event occurred at night, the Rig floor was evacuated.

Attempts to open the diverter ventline valves to relieve the rising pressure, or to contain the diverter flowline seal leak by increasing the closing pressure of the seals, failed when the remote controls could not override the "test" mode. At 0515 hrs, with gas detected on the Rig and pressure rising on the annulus and presumably the conductor casing shore, evacuation of all personnel on the Rig and Platform was completed.

By November 16, personnel had re-boarded the Rig, contained the leaking seal elements and initiated kill operations. Isolation of the source of the annular flow of gas was subsequently achieved and the normal drilling operations were resumed by 22 November 2002.

Events Leading to Loss of Control

The following table describes the drilling activities before and during the loss of control. The information is collected through interviews performed by MMS and through drilling morning reports.

Table 7: Event summary before and during leak detection.

Grand Isle Block 90, Well C-7 ST, year 2002		
Date	**Time**	**Case Observations**
oct.28 - nov.6		Spudded the Well C-7 ST and drilled 16" conductor pipe at about 1200 ft. MD, cemented to surface with returns observed at surface. No leak-off test was performed.
nov.7 - nov.11		Normal directional drilling operations, drilled to approximately 5150 ft., pumping sweep every stand. Mud weight was 9.9 ppg.
nov.12		POOH and retrieved the log data from MWD. Made a wiper trip and circulated sweep that produced a measured 350 units of gas at surface. After checking for flow and weighting up to 10.2 ppg, the well was re-circulated and the crew prepared to set surface casing.
nov.13		POOH, ripped up and ran the 10 3/4" surface casing to approximately 5140 ft. Cemented with returns to surface. Dropped and bumped plug with 1400 psi. The cement was in place at 22.45 hours, and the floats held. Ran 1" into 10 3/4 x 16 inch annulus, washed cement at 5 bpm for 15 minutes. Monitored until the returns were clean.
nov.14	02:30	While the casing valve was being monitored, the well was observed to start flowing. The casing valve was shut and the riser was filled with seawater.
	02:45	The well was shut in well by placing diverter in "test" mode. Pressure then increased to 400 psi and the diverter flowline seals started to leak. By using the lines connecting the diverter housing to the choke manifold, pressure was twice bled back to 350 psi. Pressure built back to 400 psi both times with increasing flow and fluid returns. Pressure increased to 580 psi, and flowline seals leak increased. When gas was detected on the Rig floor, the crew abandoned the rig floor, leaving the system in "test" mode. Attempts were made to open diverter ventline valves from tool pusher's

		remote station to relieve pressure. The remote would not override "test" mode and open diverter. It was also found that the diverter flowline seal pressure could not be raised from the remote site. At the remote site, the existence of a previously installed transponder-linked monitoring system provided the ability to monitor pressure.
	03:15	50 nonessential personal evacuated and transferred to GI 94B platform. The seals continued leaking.
	05:15	The last pressure monitored was 340 psi. The remaining 15 personnel were evacuated by boat to GI 94 "B".

Cause of Loss of Control

MMS (2003) assumes that the loss of control was caused by an apparent micro-annulus during the cementing of the surface casing. This micro-annulus allowed gas from the "2660-ft sand" to migrate behind the surface casing, past the conductor casing shoe and into the annulus, as Fig. 4.1 demonstrates. The gas migration caused the surface pressure and green cement/gas flow from the casing annulus, which led to the diction to hold pressure on the annulus to allow the green cement time to cure, rather than divert the flow. This action was done by placing the diverter into "test" mode, and it was the only way to shut in the system fully and immediately.

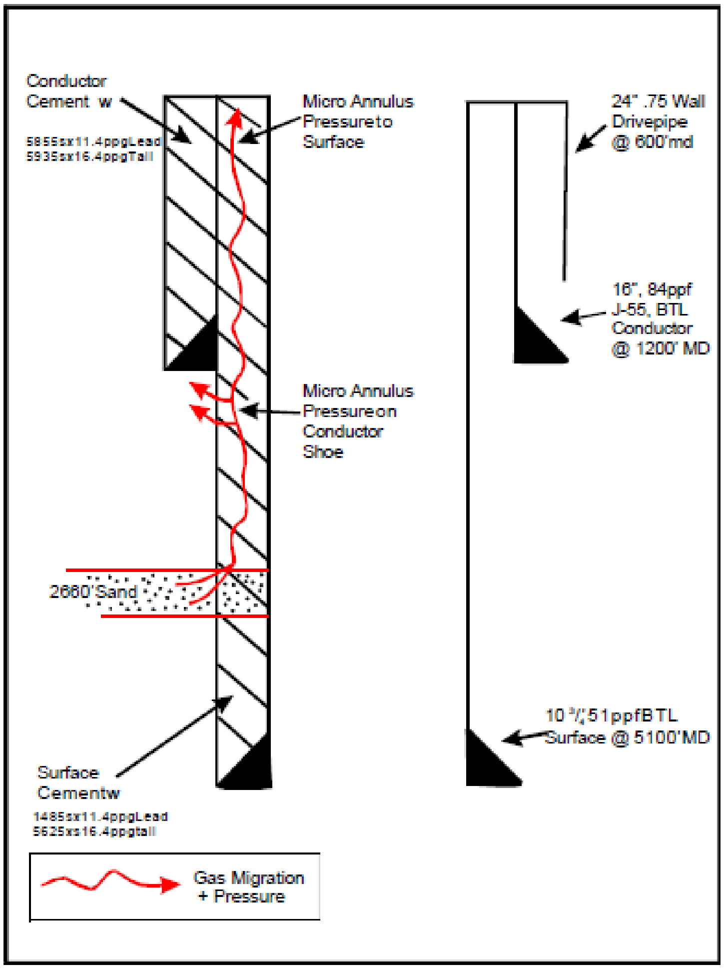


Fig. 4.1: Well Schematic and gas migrating route at time of LOC (MMS, 2003).

By doing this, the pressure on the subsurface formations and the conductor shoe was allowed to rise to levels untested by drilling or leak-off. As the pressure rose, the flowline seals developed an intermittent leak, causing the gas to be released on the rig floor. The leak was not contained by raising the flowline seal pressure because of uncertainty about the pressure handling capability of the diverter system. The continued leak of gas created conditions that required rig evacuation.

The diverter control was left in “test” mod during the evacuation of the rig floor, which made control of the diverter valves and system from the remote station impossible. The design of the diverter control was such that the diverter could not be controlled from the remote station with the system in test. The crew was unaware that the “test” mode disabled the remote station diverter control, and it eliminated the ability to contain the diverter flowline seal leak by raising the seal closing pressure. It also made it impossible to relieve the pressure on the subsurface formations and casing shoe by opening the diverter valves.

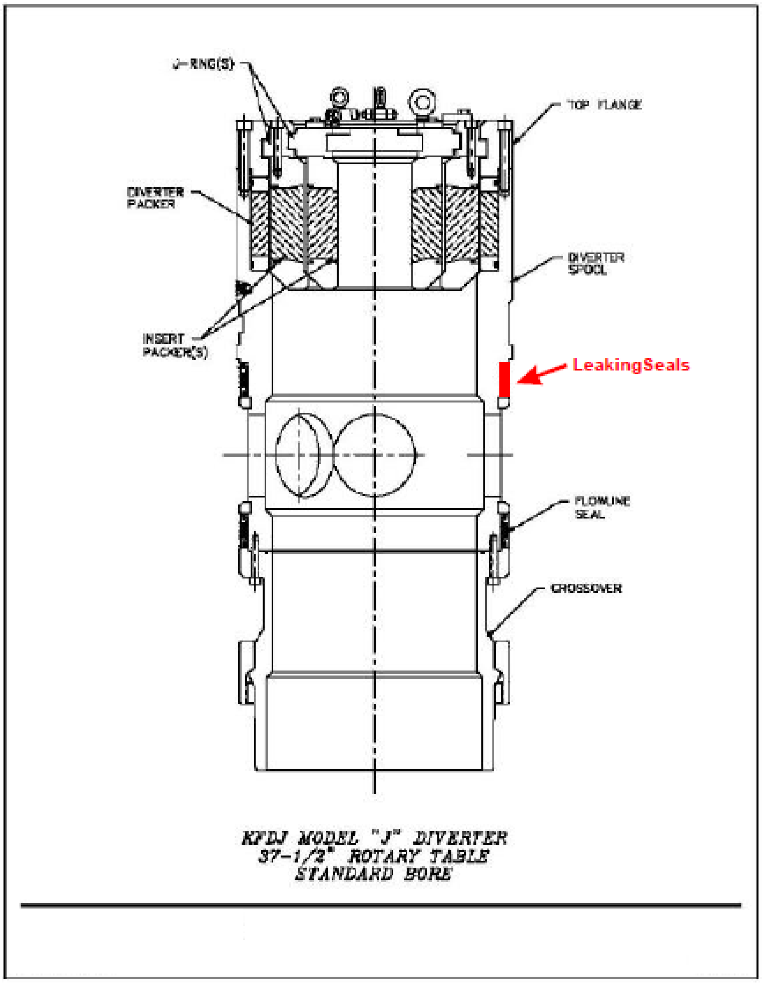


Fig. 4.2: Schematic of diverter and source of leak (MMS 2003).

Contributing Cause of Loss of Control

After having studied all available documents, MMS had some suggestions about what caused the flowline leak. It is possible that the flowline seal pressure was set at 260 psi, as the pressure found on the rig floor was accessed during kill operations. Because the annular pressure was reported to have reached as high as 580 psi, the inability of the seals set at 260 psi to contain pressure is a possible cause of the leakage.

It is also possible that the intermittent leak of the diverter flowline seals was related to compression and tension forces transferred to the seal elements by rocking motion of the rig. These forces, when added to the casing pressure, possibly created an intermittent leak by momentarily causing the shut-in pressure of the seals to be exceeded as the rig swayed.

Concept Summary from the Grand Isle Block 90 Incident

During the investigation of the accidents new concepts and relations between them emerges. To expand the Knowledge Model, all these concepts have to be implemented in the model.

Table 8: Concept from case study and their placement in the ontology structure. New concepts retrieved from the MMS-evaluation and suggested by present author are highlighted in bold. The concepts already implemented in the model, but mentioned in the specific incident, have been inserted with normal font.

Concept	Position in the ontology
Uncontrolled Flow In Cemented Annulus	**Error**
Leak Through Diverter	**Error**
Shutting In Diverter	**Activity**
Increasing Upper Annular Pressure	**Parameter**
Bleeding Off Pressure	**Activity**
Uncertainty About Equipment Use And Limitations	**Human Error**
Missing LOT	**Parameter**
Gas Migration	Process
Flow From Conductor Casing	**Error**
Detected Gas On Rig	**Parameter**
Increasing Formation Pressure	**Parameter**
Poor Pre-Event Planning	**Human Error**
Poor Procedure/Documentation	**Human Error**
Previous Blowout In Neighbor Well	**Parameter**
Increasing Annular Pressure	Parameter
Rocking Motions Of Rig	**Parameter**
Cyclic Diverter Fatigue	**Parameter**

4.1.2 The Well A-13, Eugene Island Block 284 Incident

The Well A-13, Eugene Island Block 284 Incident, from now on referred to as Case 1, occurred on March 1 2001, during an attempt to weld the casing head of a slip-on wellhead. Gas flow was noticed coming from the annular bleed valve and unsuccessful attempts were made to stop the flow, which came from the drive pipe/surface casing annular region. The gas flow eventually ignited and caused extensive damage on the platform. The well bridged over and kill operations were completed. No personnel injuries occurred.

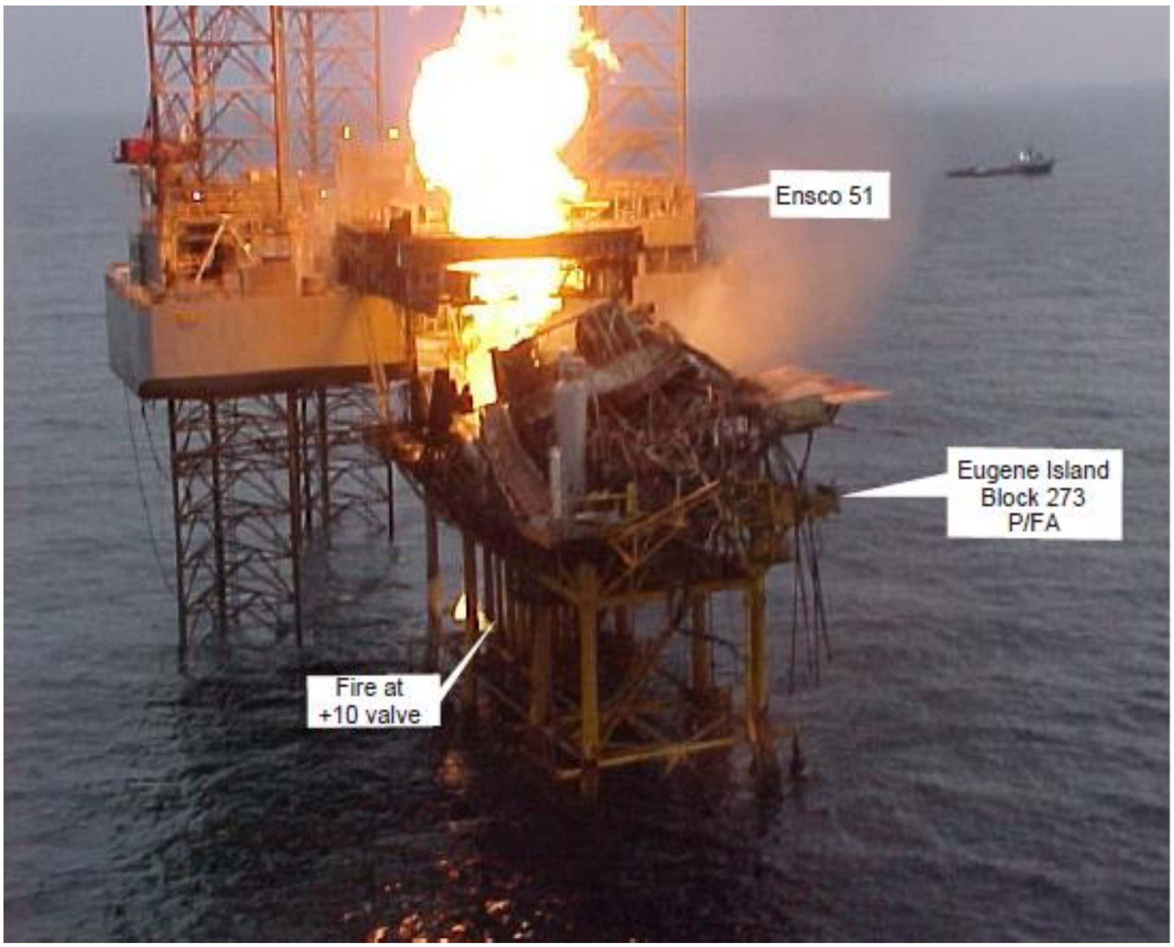


Fig. 4.3: Platform/rig on fire (MMS 2001).

Background Information

Lease OCS-G 0991 covers approximately 5000 acres and is located in Eugene Island Block 284, Gulf of Mexico, off the Louisiana coast. The lease was issued effective June 1, 1962, and Forest Oil Corporation became designated operator of the lease on June 8, 1962. Platform A was installed in 1970.

Fig. 4.4: Location of Leases OCS-G 0987 Eugene Island Block 273 (surface location) and OCS-G 0991 Eugene Island Block 284 (bottom hole location), (MMS 2001).

On February 9, 2001, the MMS Lafayette District approved Forest Oil Corporation's Eugene island Block 284, Lease OCS-G-0991, Well A-13 Application for Permit to Drill (APD). In the APD, Forest Oil Corporation proposed drilling Well A-13 to a measured depth (MD) of 5476 feet and a true vertical depth (TVD) of 5153 feet, using the Enso 51 jack-up rig. The well would be located in 191 feet of water.

Forest Oil Corporation anticipated driving the 24” drive pipe to a measured depth of 441 feet MD/TVD, drilling a 22” conductor hole and setting a 16” conductor casing at 650 feet MD/TVD, drilling a 14 ¾” surface hole and setting 10 ¾” surface casing at 1900 feet MD/TVD, and drilling a 9 7/8” production casing hole and setting a 7 5/8” casing at 5476 MD/5153 feet TVD.

Activities Prior and Through Loss of Control

Eugene Island Block 284, OCS-G 0991 Well A-13, year 2001		
Date	Comment	Case Observations
feb.23 - feb.26	Pre Loss Of Control	The Well A-13 was spudded and drilled to 1700 feet MD/TVD.
feb.27		Two logs were run from 1694 feet MD/TVD to 633 feet MD/TVD. The logs showed sands at 710 feet MD/TVD and 1170 feet MD/TVD. Once the logging tools were POOH, a 14 3/4" hole opener was picked up and run to 1700 feet MD/TVD. No fill was detected.
feb.28		Surface casing were run in hole to 1700 feet MD/TVD and cemented in place. After the WOC period (8 hours), the annular bleed valve (+10 valve) was opened to drain the fluid in the 24" drive pipe by the 10 3/4" surface casing. The 10 3/4" surface casing was then cut roughly, before final cuts began.
march 1	Loss of Well Control	Final cuts were completed, while the means of removing the annular bleed valve were examined. The well was static at this time. The 10 3/4" slip-on wellhead (SOW) by 11", 5000-psi casing head was lowered down to the wellbay for installation and set on the 24" drive pipe and 10 3/4" surface casing. The SOW was leveled, the area was sniffed for gas and the welder tacked the 24" base plate in four places. The SOW was preheated and the welder began to weld on the inside of the SOW. After the 3rd welding rod was burned, a small blue flame was observed. The fire was extinguished and thought to be caused by grease from the wellhead. The area was

		sniffed for the presence of gas, resulting in no detection of any gas. Operations resumed, and a second flame ignited. This one was larger than the previous. The flame was distinguished and the area was once more sniffed for gas. This resulted in maximum level of gas present showed by the gas detector. Approximately 0130 hours, the night driller observed a slight flow at the annular bleed valve.
march 1 - march 2	Attempts to Stop Well Flow	The onsite Forest Company representative was alerted about the fluid and gas escape from the valve, and immediately instructed the crew to close it to establish additional hydrostatic head by using 8.6-ppg seawater. An attempt was made to add seawater to the annulus through a 1/2" gap located between the base plate and the 10 3/4" surface casing. Because of the size of the opening on the base plate and the rate of the seawater being added, sufficient volume could not be added to slow down the current well flow. The flow continued at an increasing rate, and attempts to stop the well flow by adding mud to the 24" drive pipe were unsuccessful. As a last attempt to control the well, the Forest Company representative decided to open the annular bleed valve to allow the 19.0 ppg mud to displace the lighter fluid present inside the 24" drive pipe by 10 3/4" surface casing annulus. With the flow of the well still increasing and all attempts of adding mud to the 24" drive pipe by 10 3/4" surface casing annulus failing, the valve was closed. At approximately 0300 hours, a decision was made to evacuate the rig, and the valve was again opened in an attempt to divert flow away from the platform and rig.

Cement Operations on the Well A-13

The 16” liner was cemented with a total of 1035 cubic feet of cement. After pumping 119 barrels of tail cement, the annular bleed valve was opened and the cement job was completed with full return taken at the valve. The pressure was released and the float equipment was holding.

The 10 ¾ “ surface casing was cemented with a total of 1897 cubic feet of cement. Full returns were observed during the entire cementing procedure, with a total of 30 barrels of cement returns observed at the annular bleed valve. The pressure was released, and the float equipment was holding.

Although both the 700-foot and the 1200-foot sands were known to be present in the original well planning, the above 10 ¾” casing cement design did not include any additives for shallow-gas control. Further, the cement was not redesigned for the presence of shallow gas after the well was logged. The only change done was the reduction in cement volume based on the caliper log.

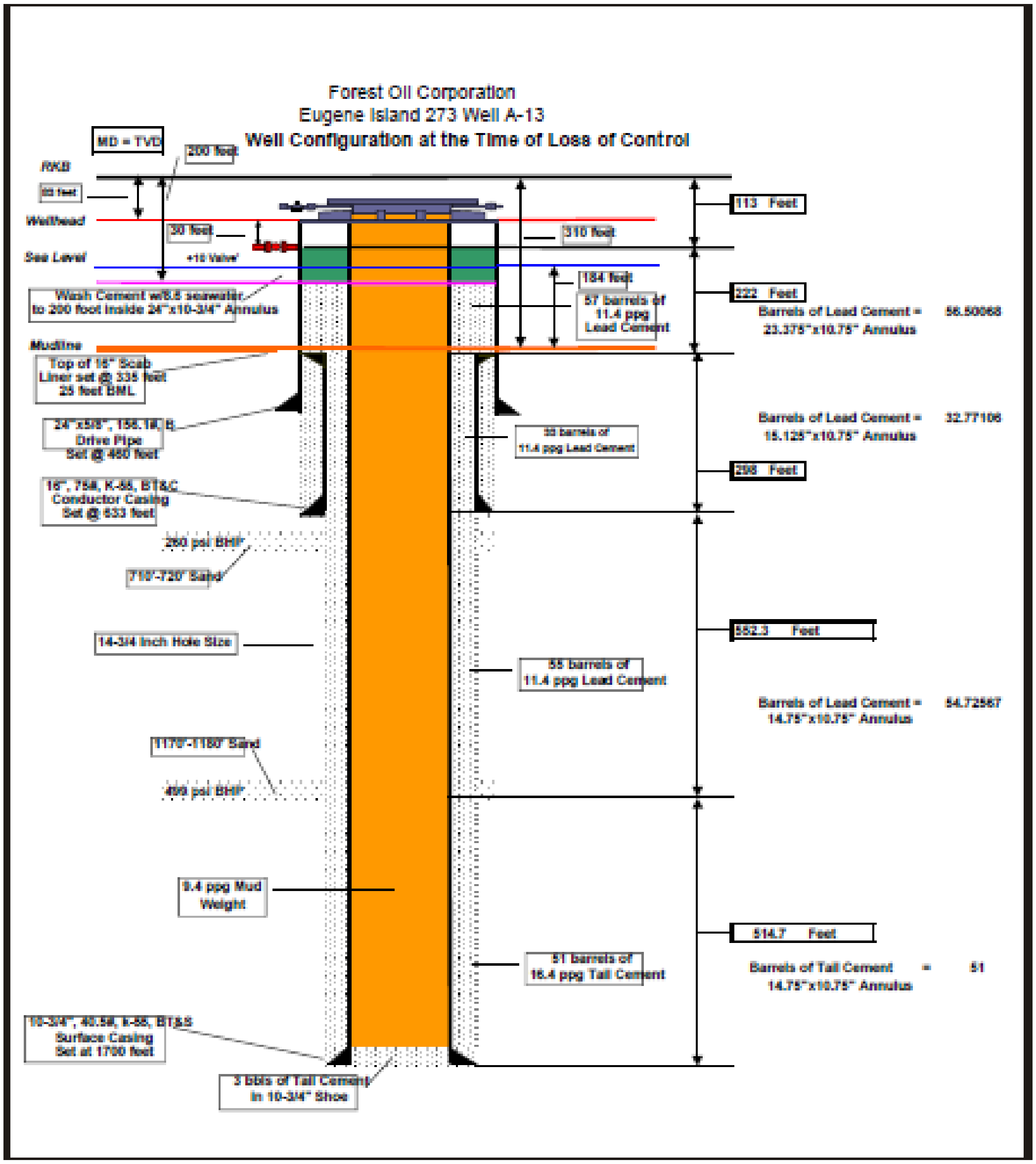


Fig. 4.5: Eugene Island Block 273, Well A-13, wellbore schematic, (MMS 2001).

The cementing company representative was never made aware of any shallow-gas hazards. To the MMS he stated that if he had been aware of the shallow-gas hazards he would have "requested a lab report from their engineering department so that they could redesign their slurry to combat gas".

Gas flow must have occurred from either the 700-foot and/or the 1200-foot sand. The flow was not apparent at the surface during or right after the 10 ¾" surface casing was cemented, but occurred at the time when the cement is going through the gelation phase. At this time, the cement loses its ability to transmit hydrostatic pressure onto the formation and allows for gas to migrate into it.

The Forest Management did not review the drilling program developed by the drilling engineer prior to its implementation. A prespud meeting prior to conducting drilling operations was also not conducted. Communication was incomplete between the Forest Management and the cementing company representative. Forest Management stated that "a form" is used to communicate pertinent information to the cement service company, such as shallow-gas hazards. The investigation could not determine whether the form was used or the form was used without reference to shallow-gas hazards. When Forest Management were asked why the cement company didn't recommend revising the cement design appropriate for controlling shallow-gas hazards, the response was "I think there was obviously a communication breakdown there".

Causes of Loss of Control

The most vulnerable period for the cement is immediately after placement and prior to setting. It is during this time that cement, while developing gel strength, becomes self-supporting and loses its hydrostatic pressure. This hydrostatic pressure loss is responsible for the well reaching an underbalanced condition, which can lead to gas invasion. Slurries must be designed with the idea of minimizing this vulnerable time when and underbalanced condition exists.

According to the MMS the main cause of the incident was migration of formation gas from the 700-tf sand and/or the 1200-ft sand. They believe the gas went into the cement between the 24" drive pipe and the 10 3/4" surface casing because of the above mentioned loss of hydrostatic pressure.

Assumed contributing causes are listed below:

1) Failure of Forest Personnel to communicate the presence of shallow-gas hazards to the contract cement service company resulted in cement not being properly designed to prevent gas migration.

2) A prespud meeting was not conducted to communicate the known shallow-gas hazards to all parties involved in the drilling operations.
3) Once the hole section was logged and revealed the presence of shallow gas, the well log information was not analyzed to verify that the cement program was properly designed for shallow gas.
4) Opening of the annular bleed valve allowed the fluid level in the 24" drive pipe by the 10 ¾" surface casing annulus to fall, which reduces the hydrostatic pressure on the cement. This could have contributed to gas migration into the wellbore.

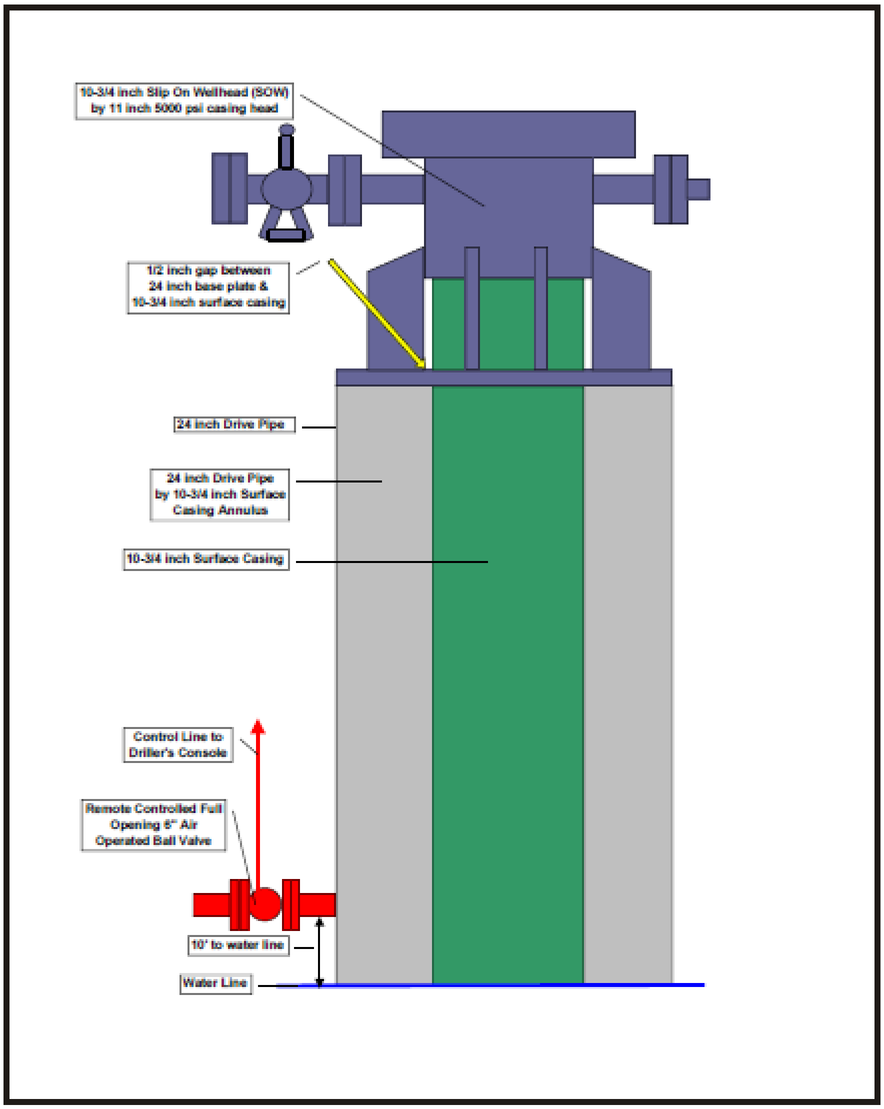


Fig. 4.6: Slip-on wellhead schematic and +10 valve schematic (MMS 2001).

Concept Summary from the Eugene Island Block 284 Incident

Table 9: Concept from case study and their placement in the ontology structure. New concepts are highlighted in bold.

Concept	Position in the ontology
Leak Through Annular Bleed Valve	**Error**
Detected Gas On Rig	**Parameter**
Sand Zone Through Open Hole	**Parameter**
Small Fire Ignited On Rig Floor	**Parameter**
Increasing Annular Pressure	Parameter
Bleeding Off Annular Pressure	**Activity**
Decrease In Annulus Fluid Level	**Parameter**
Missing Shallow Gas Additives In Cement Slurry	**Parameter**
Miscommunication	**Human Error**
Uncontrolled Flow In Cemented Annulus	Error
Gas Migration	Parameter
Insufficient Risk Analysis	**Human Error**
Hydrostatic Pressure Loss In Cement Slurry	**Parameter**

4.1.3 The Well A-6, East Cameron Block 328 Incident

The Well A-6, East Cameron Block 328 Incident , from now on referred to as Case 2, consisted of a serious blowout and fire that occurred on the morning of April 1, 1997. The platform rig Pride 1001E was at this time conducting drilling operations on Well A-6 for American Exploration Company on Lease OCS-G 10638 at the East Cameron Block 328 in the Gulf of Mexico, offshore Louisiana. Personnel from Lafayette District of the MMS, Gulf of Mexico OCS Region, flew over the scene on April 1, 1997. The overflight of the area revealed that the platform and rig were totally engulfed in fire. The MMS personnel proceeded to board the motor vessel Subsea Mayo and were able to monitor the blowout and fire. On April 4, 1997, the Derrick Barge 50 arrived on location and was able to extinguish the fire with spray cannons. The well finally bridged over on April 10, 1997.

Lafayette District personnel were able to board the platform on April 15, 1997, and inspect the scene of the accident. The Investigative Panel conducted a hearing on July 29 and July 30, 1997, where involved parties were questioned.

After a hearing, during which involved parties in the incident were questioned, and after having considered all information available, the MMS Investigative Panel produced the report this chapter is based upon.

Background Information

Lease OCS-G 10638 covers approximately 5000 acres and is located in East Cameron Block 328. On September 30, 1996, Union Pacific Resources Company designated American Exploration Company as the operator of East Cameron Area Block 328. The Application for Permit to Drill (APD) for Well-6 was approved January 14, 1997, and drilling operations began on March 25, 1997 using the platform rig Pride 1001E. Prior to drilling operations of Well-6, Wells A-4 and A-8 were drilled February 19, 1997 and March 23, 1997, respectively. During the drilling of Well A-6, simultaneous operations involving production of oil and gas from Wells A-1, A-2 and A-4 were ongoing.

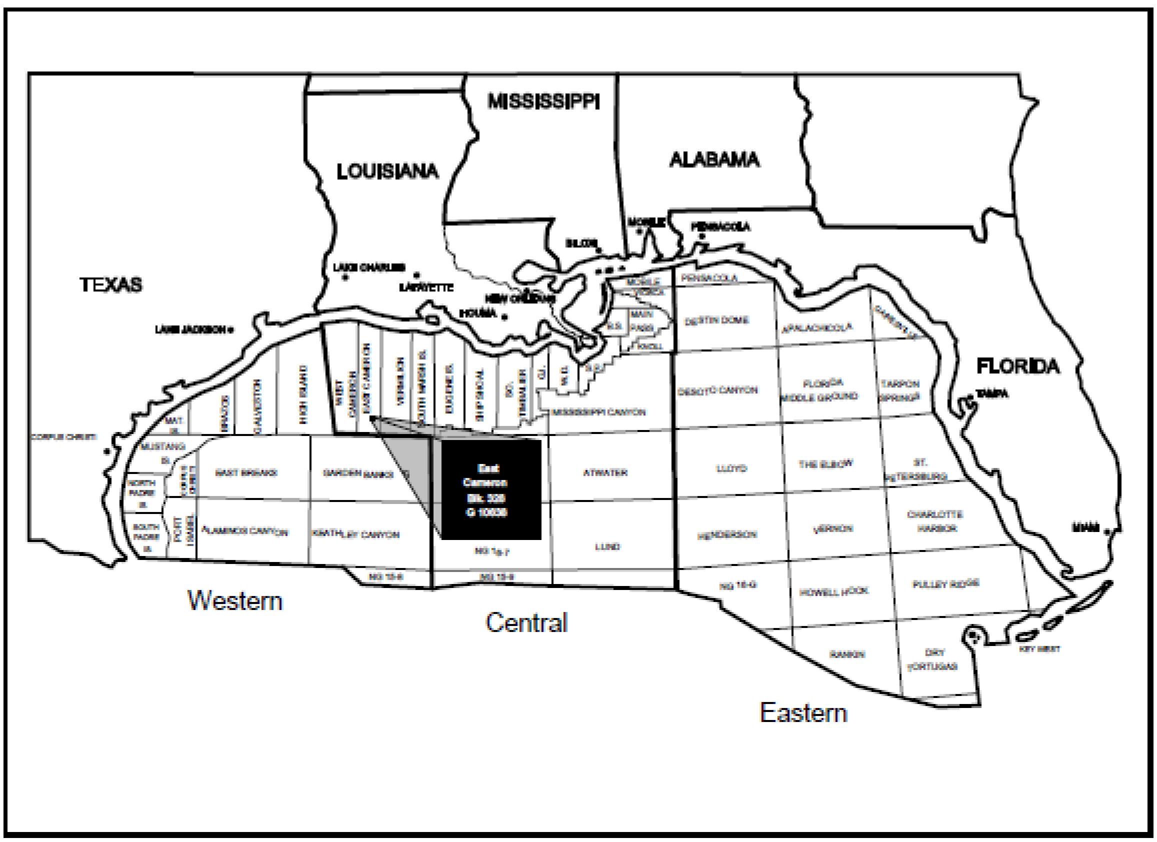


Fig. 4.7: Location of Lease OCs G-10638, East Cameron Block 328, (MMS 1997).

Description of the Incident

At approximately 12:15 a.m., on April 1, 1997, a serious blowout and subsequent fire occurred on Platform A in East Cameron Block 328. After cementing the 9 5/8" casing, annular flow was observed between the 9 5/8" casing and 13 3/8" casing while the blowout preventer stack was being nippled down.

Attempts were made to stop the flow by using a casing swedge and reattaching the hydraulic control lines to the BOP. The crew was able to put the casing swedge in place, however, it did not mitigate the flow of mud, cement and gas. The crew was not able to reattach the hydraulic control lines because of the increasing well flow.

The production platform was shut in using an emergency shut down (ESD) station and the decision was made to evacuate. All 42 personnel were evacuated by a standby workboat. No injuries were sustained during the accident and all personnel were taken to the nearby jack-up rig Adriatic 7. Within one and one-half hours of evacuation, the gas flowing out of the annulus ignited.

The fire was extinguished on April 4, 1997, and cleanup operations began. However, the well was still flowing mud, sand, water and gas. On April 9, 1997, the well was accidentally ignited by a cutting torch. The well bridged over on April 10, 1997.

Preliminary Activities

In the APD, American Exploration Company proposed drilling a horizontal well to a measured depth (MD) of 5422 feet and true vertical depth (TVD) of 2845 feet. The well would be located in 243 feet of water. American Exploration Company anticipated driving a 20" casing to a measured depth of 595 feet MD/TVD, drilling a 17 ½" conductor hole and setting a 13 3/8" conductor casing at a measured depth of 1200 feet MD/TVD, drilling a 12 ¼" hole and setting a 9 5/8" casing at 4623 feet MD/2845 feet TVD, and drilling a 8 ½" horizontal hole to a total measured depth of 5422 feet/2845 feet TVD, as per the directional plan.

On March 24, 1997, Pride 1001E was skidded over Well A-6 and the 20" drive pipe was driven to a measured depth of 595 feet. On March 26, 2997 the 20" diverter system was installed, tested and Well A-6 was spudded. A 17 1/2 " hole was drilled to 1200 feet MD/TVD, and the day after the 13 3/8" casing was run and cemented. Slips were set on the 13 3/8" casing and the 20" diverter system was rigged down. On March 28 a final cut was made on the 13 3/8" casing and a 20x13 5/8", 3000 psi wellhead was installed. The 13 5/8" BOP stack was installed and tested to a low pressure of 250 psi and a high pressure of 3000 psi. a 12 ¼" bit and steering assembly were run in the hole to 1146 feet MD/TVD, and the casing was tested to 1500 psi. After drilling out the casing float equipment and 10 feet of new formation, a leak-off test was performed on the casing shoe with a 180-psi surface pressure resulting in a 12.5 ppg equivalent mud weight shoe test.

Through March 31, 1997, drilling operations continued on Well A-6 to a depth of 4919 feet MD/2846 feet TVD. The 12 ¼" hole was circulated and conditioned in preparation of running the 9 5/8" casing. The casing was run and cemented starting at approximately 5:00 p.m. on March 31, 1997. It was cemented with 1000 sacks of cement with the lead slurry weighing 11.6 ppg and the tail slurry weighting 16.2 ppg. Three plugs were used, with the first plug being pumped ahead of the lead cement. After the 1000 sacks of cement had been pumped, the second plug was dropped behind the tail cement, and additional 10 barrels of cement were pumped behind the second plug. This cement was the inflation cement to be used to inflate the external casing packer (ECP) located above the float collar. The third plug was pumped behind the inflation cement to keep that portion of the cement together. Saltwater was then pumped to displace the casing and bump the second plug.

During pumping of the saltwater, the pressure was expected to reach about 1000 pounds as the second plug bumped. However, at 800 pounds, there was a drop in pressure of about 250 pounds and it was assumed the second plug had been bumped and the ECP had inflated. It was then assumed that approximately 10 more barrels of salt water would be needed to bring the pressure up to 1000 pounds. After a total of 12 barrels of saltwater were pumped, the pressure was only 640 pounds and not rising. The pumping was stopped and a discussion was held between the company man, the Baker Oil Tools man and the drilling consultant. During this discussion, it was assumed that ECP had ruptured and that there would be no consequences from this rupture if operations continued.

The pressure was then bled off the casing, thereby completing the cement job for the 9 5/8" casing. The cementing job took approximately four hours and was conducted at about 9:00 p.m. During the pumping of the 1100 sacks of cement, returns were noted with one interruption of approximately one to two minutes. One witness account of the cementing procedure indicated that the first plug bumped approximately 40 barrels late. It is to be noted that the crew change occurred at 6:00 p.m. and included the tool pusher, driller and floor hands.

Loss of Well Control

After the cement job was completed, the crew proceeded with readying the well for the removal of the 13 5/8" BOP stack. Prior to nippling down, the rig crew drained and washed the BOP stack, and disconnected the two accumulator lines located on the annular preventer. A cradle, located around the annular preventer, was removed. Cables were then secured to the BOP stack. The BOP's could then be lifted, allowing for a rough cut on the 9 5/8" casing. Prior to the BOP being lifted, a floor hand was hit with mud, and he noticed the BOP stack was full. The driller proceeded to the shale shaker pit and saw a small amount of mud in the ditch that had just been cleaned. The driller then looked into the BOP stack and noticed that the stack had filled back up and was bubbling.

Attempts to Stop Well Flow

A casing swedge was installed on the 9 5/8" casing, but did nothing to alleviate the flow from the well. Meanwhile, attempts were made to reconnect the accumulator lines to the annular preventer. The well began blowing and attempts to reconnect the accumulator lines to the annular preventer failed. A decision was made to activate the ESD system for the production on Platform A. When the company man and day tool pusher were awakened at around midnight, they attempted to shut in the annular preventer from the remote BOP panel, not knowing that the accumulator lines had been disconnected. This emptied the accumulator of all the fluid. They then tried unsuccessfully to shut the blind rams. The decision was then made to evacuate.

Assumed Causes of Loss of Control

The MMS Investigative Panel concluded that the most probable cause of the incident was formation gas migrating through the cement between the 9 5/8" casing and the 13 3/8" casing. Contributing causes to this could have been that there was not enough wait-on-cement time prior to nippling down the BOP. The BOP accumulator pressure was also drained immediately due to the hydraulic control lines being disconnected.

The panel concluded that the temporarily lost returns, as well as the first rubber cement was noted being bumped 40 barrels late could have been contributing causes to the accident and may have indicated problems with the cement job.

Because the well was being drilled horizontally, the MMS assumes that casing may not have been properly centralized, resulting in a non-uniform cement job. It is though more likely to believe that the poor centralized casing may have contributed to axial dispersion of the cement slurry, which leads to early cement return. This early cement return may have confused the witness on the rig to believe that the cement was bumped too late, when it actually can be explained by high annular dispersion of the cement slurry.

It was unclear to the MMS if the ECP not behaving as expected, and presumably rupturing, had any effect.

Concept Summary from the East Cameron Block 328 Incident

Table 10: Concepts from case study and their placement in the ontology structure. New concepts are highlighted in bold.

Observed concepts	Position in the ontology
Blowout	Failure
High Well Inclination	Activity
Early Cement Return	**Parameter**
Temporarily Lost Returns	**Parameter**
Maintaining Annular Fluid Level	**Parameter**
Bubbling Mud In BOP Stack	**Parameter**
Too Short WOC Time	**Activity**
Gas Migration	Parameter
Poor Centralized Casing	Parameter

Non-Uniform Cement Column	Parameter
Ruptured External Casing Packer	**Error**
Sudden Pump Pressure Drop	**Parameter**
Cement Escape To Formation	**Parameter**

4.1.4 The Well A-5 ST01, High Island Block A-368 Incident

The Well A-5 ST01, High Island Block A-368 Incident, from now on referred to as Case 4, consisted of a well blowout occurring during the period between May 9 and May 18, 2001. At that time drilling operations were performed by Devon Energy Production Company, L.P.

The site was visited and inspected by James Hail and Ronald Lee Fowler on May 10 and 12, 2001. Numerous digital photographs of the scene were taken by representatives of MMS and Devon. A meeting was held June the same year to discuss all aspects of the incident. Interviews with key personnel were conducted on the rig June 14 and 26, 2001. Incident summaries and descriptions were taken from personnel during these interviews. Teleconferences were held, and the panel members met at various times throughout the investigative effort. After considering all information available, they produced the report this chapter in based upon.

Background Information

Lease OCS-G 2433 covers Block A-368 of the High Island Are, East Addition, South Extension, Gulf of Mexico, approximately 105 miles from the Texas coast in 314 feet of water. The lease was initially issues effective August 1, 1973, covering 5760 acres. Effective August 29, 2000, Devon Energy Production Company was designated as operator. Devon Energy had contracted Global Marin Drilling Company to conduct the drilling operations on Platform A using the MODU Glomar Baltic 1.

Description of Incident

The blowout occurred after cementing the 13 3/8" surface casing, and lasted from May 9 to May 18, 2001. After completing the cementing, a slight flow was noted coming from the annulus between the surface casing and the 18 5/8" conductor casing. The diverter was closed and pressure started increasing in the annulus. Valves and piping were rigged up to the 18 5/8" A section to permit monitoring of pressure and transport of fluids from the annulus.

Throughout the night of May 8 and through 07:30 hours on May 10, unsuccessful attempts were made to bleed off the annular pressure. On May 10, 2001, gas belched from the 22" drive pipe of Well A-10 ST01, located one slot south of Well A-5 ST01. There were no gas bubbles coming from the A-5 ST01 drive pipe at this time. However, in the ensuing 15 minutes, gas bubbles were observed around other wells at the water line. Within an hour, all 57 personnel on the rig and platform were evacuated.

The flow eventually ceased, and the rig was re-manned on May 12, 2001. Attempts to salvage the well failed, and it was therefore plugged and abandoned. The rig was released on June 16, 2001.

Well Planning

The A-5 ST was to be the last of the seven-well program to be drilled by the Glomar Baltic 1 from Platform A. in all, 23 wells including sidetracks, had been drilled from the platform. The bottomhole location for Well A-5 ST was planned to be located in High Island Block A-351, Lease OCS-G 2429. However, because of the blowout, the well was terminated with the final bottomhole location on High Island Block A368, Lease OCS-G 2433.

The A-5 ST well plan, including the plan for setting and cementing the surface casing, was based on the drilling programs of Wells A-7 ST and A-10 ST. Because of the high angle of this holes, there were no plans to reciprocate the surface casing while circulating and pumping the cement job.

The fracture gradient at planned surface setting depth was too weak to support a full column of tail slurry that would extend above a shallow gas sand. Only the lead slurry would cover the sand and extend to the surface.

Activities Preceding the Blowout

The original well, A-5 ST00 BP00, was plugged, and a mudline sidetrack, Well A-5 ST01 BP00, was initiated. The drive pipe was driven and the conductor casing was set and cemented after four attempts because of tight spots. The 12 ¼" surface hole was drilled and opened to 17 ½" without any significant incidents. A shallow gas sand was penetrated in this well. The same sand was the source of the blowout that occurred during drilling of Well A-3 in March 1980.

Surface casing was run to depth on May 8, 2001. A TIMCO tool was used to keep the casing full of mud while running and to circulate bottoms up immediately after the casing was run. The top of the last joint of casing was several feet above the rig floor.

The top drive became inoperative because of the failure of an electrical relay in the top drive control panel. The relay was bypassed, but the top drive would not function. Approximately five hours were spent troubleshooting this problem, during which time mud was circulated. The TIMCO tool could not be removed without use of the top drive because of the elevation of the last joint of the casing.

After the top drive was back in service, the TIMCO tool was removed from the casing and the cementing head was installed. On May 8, 2001, at 06:14 hours, cement lines were rigged up and pumping of the cement began. During the cement job, returns were lost of approximately 10 minutes when the cement reached the casing shoe. Cement returned to the surface 72 barrels earlier than anticipated. The cement job was completed at 09:30 hours the same day.

The Blowout

Five hours after pumping, at approximately 14:30 hours, May 8, 2001, cement was washed out to 130 feet from the annulus between the surface casing and the conductor casing. At that time, a slight flow began and the diverter was shut in. The motor vessel Dakota was called to the rig when the problem was first noted and arrived on location at 02:30, May 9.

Pressure built up to 250 psi within an hour and later to 470 psi before reaching 560 psi shortly after. Bubbles were then noted between the rig and the platform. Lines were rigged up to bleed the casing pressure through the choke manifold, and gas were bled from the annulus six times at 5-minute intervals. These efforts failed to bleed off the casing pressure. Beginning at 18:00 hours on May 9, 2001, 11-ppg mud was lubricated into the casing. The plan was to pump mud into the annulus until pressure reached 750 psi, wait, and then bleed gas until the pressure decreased to 560 psi. After 12 hours, 23,5 barrels of mud had been lubricated.

Over a 45-minute period, beginning at 06:45 hours at May 10, 13 barrels were bled from the annulus. The pressure decreased to 20 psi. At 07:30 hours, gas belched from the annulus between the drive pipe and conductor casing of Well A-10. No activity was noted from the A-5 ST drive pipe. All production operations were shut in. The bubbling increased to a boil between the rig and the platform, and the rig was fully evacuated by 09:00 hours the same day, just some hours after the cement job. The uncontrolled gas flow also caused a boil around the entire platform.

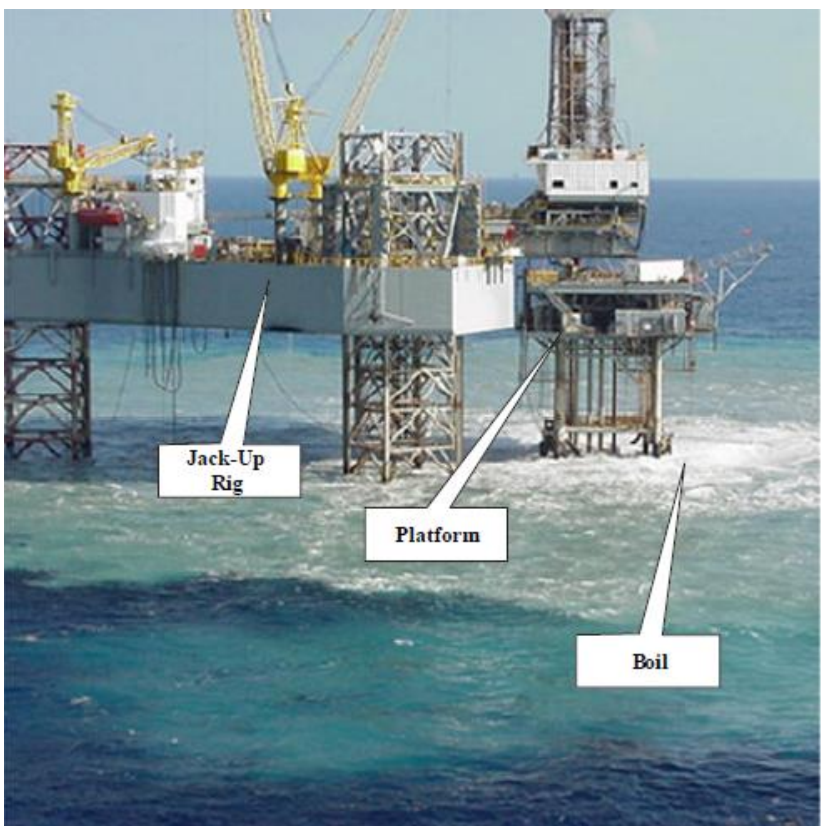


Fig. 4.8: Photograph of the platform and rig during gas flow to sea surface (MMS 2001).

The platform was monitored, and the flow had greatly diminished by 17:00 hours at May 11, 2001. Two hours later a ROV performed an underwater survey around the rig and found no signs of gas. The rig was then re-boarded by Boots and Coots and essential personnel at 09:00, May 12. A pressure of 240 psi was noted on the 13 3/8" by 18 5/8" annulus of the Well A-5 ST01. A noise and temperature log was run, indicating that flow was coming from the previously mentioned shallow gas sand.

On May 13 a second noise and temperature log indicated that flow from the sand had subsided. A sector bond log was run and confirmed that no cement bond existed behind the pipe above the sand. On May 16 the surface casing was cut with a saw, slips were installed, the diverter removed and blowout preventers were nippled up. Two days later the surface casing was perforated above the sand and the first cement squeeze was performed. All the bubbles around the platform ceased, and the ROV indicated that there were no gas bubbles at the mudline. During the period from May 19 through May 26, the casing was successfully squeeze-cemented through even shallower perforations to ensure isolation of the annulus.

Operations were begun to salvage the well by drilling out of the casing. A hole was found in the casing above the sand. Six unsuccessful attempts were made to squeeze cement into the hole. During washing out below the hole with a watermelon mill, the drill pipe became stuck and was backed off. The well was permanently plugged and the rig was released on June 16, 2001.

Assumed Causes of Loss of Control

The MMS investigative panel concluded that the source of the gas that flowed through the ST A-5 surface/conductor annular region and the gas that flowed to the sea surface is the previously mentioned shallow gas sand. Although the squeeze cementing of the annular region coincided with the cessation of the sea boil, they could not know the definite mechanism(s) by which the gas flowed to the sea surface.

The MMS investigative panel suggested contributing and other probable causes to the well control situation to be:

1) The density and pressure regression properties of the cement led slurry are considered to have been a contributory factor. Normal operating practices were followed during drilling of the surface hole was drilled with adequate mud weight.
2) Probable causes of the well situation are:
   a. Regression of cement from the mixed weight of 11,4 ppg to a seawater gradient of 8,65 ppg and/or
   b. Formation of a channel while the cement was pumped.
3) Contributing causes of the well control situation are may include:
   a. The delay in pumping cement into the surface casing of Well A-5 may have contributed to the formation of the channel. A loss of well control did not occur on Wells A-7 and A-10, where the cement was pumped much sooner after landing the surface casings.
   b. The loss of returns when the cement reached the casing shoe indicates a fracture of the formation. This may have contributed to formation of the channel.
   c. Well A-5 may have penetrated formations more susceptible to washout and lost returns than Wells A-7 and A-10, since Well A-5 was closer to Well A-3 than Wells A-7 and A-10 at the aforementioned shallow gas sand.
   d. The delay in cementing the surface casing may have resulted in a channel. This delay was caused by the difficulty in removing the TIMCO fill-up circulation tool from the casing.
   e. The explosion prevention timing system de-activated the top drive. This problem required an extended period of time for troubleshooting.
4) The loss of head resulting from washing 130 ft. of cement from the 13 3/8" by 18 5/8" annulus would not have caused the accident.
5) The decision to lubricate mud into the annulus to stop the gas flow prevented any gas from actually reaching the rig floor. Not lubricating mud into the annulus would have resulted in potentially catastrophic consequences such as occurred on Well A-3.

Concept Summary from the High Island Block A-368 Incident

Table 11: Concept from case study and their placement in the ontology structure. New concepts are highlighted in bold.

Concept	Position in the ontology
Blowout	Failure
High Well Inclination	Parameter
Increasing Annulus Pressure	Parameter
Low Surface Fracture Gradient	Parameter
Drilling Through Shallow Gas Sand	Activity
Weaker Cement In Zone	**Parameter**
Previous Blowout In Neighbor Well	Parameter
Temporary Lost Return	Parameter
Early Cement Return	Parameter
Flow Indication Through Noise Log	**Error**
Flow Indication Through Temperature Log	**Error**
Unable To Reciprocate	**Parameter**

4.1.5 The Well 30/3-A-23- A, Veslefrikk A Incident

On November 5, 2009, Statoil detected a pit on the seabed close to the well 30/3-A-23 A at Veslefrikk A at the Norwegian Continental Shelf. The reservoir injectors were sequentially shut down, as well as the production, because the pits had indications of oil and gas. No changes of activity in the pit were observed, and Statoil concluded that the pit was related only to the cuttings injection in the 30/3-A-23 A well. The last injection was done the last night before the discovery.

Seabed Mapping revealed several pits on the seabed around Veslefrikk. Observations of seashells in many of the pits indicated that these were older pits and naturally formed by shallow gas in the formation below. Two pits showed signs of activity, possibly connected to the injection, and had to be investigated. The incident is known as the Well 30/3-A-23-A, Veslefrikk A Incident, but will from now on be referred to as Case 5.

The active pits discovered were pit No.1 positioned by leg C3 and pit No.2 positioned 65 m North West for leg C3, as illustrated in Fig. 4.9.

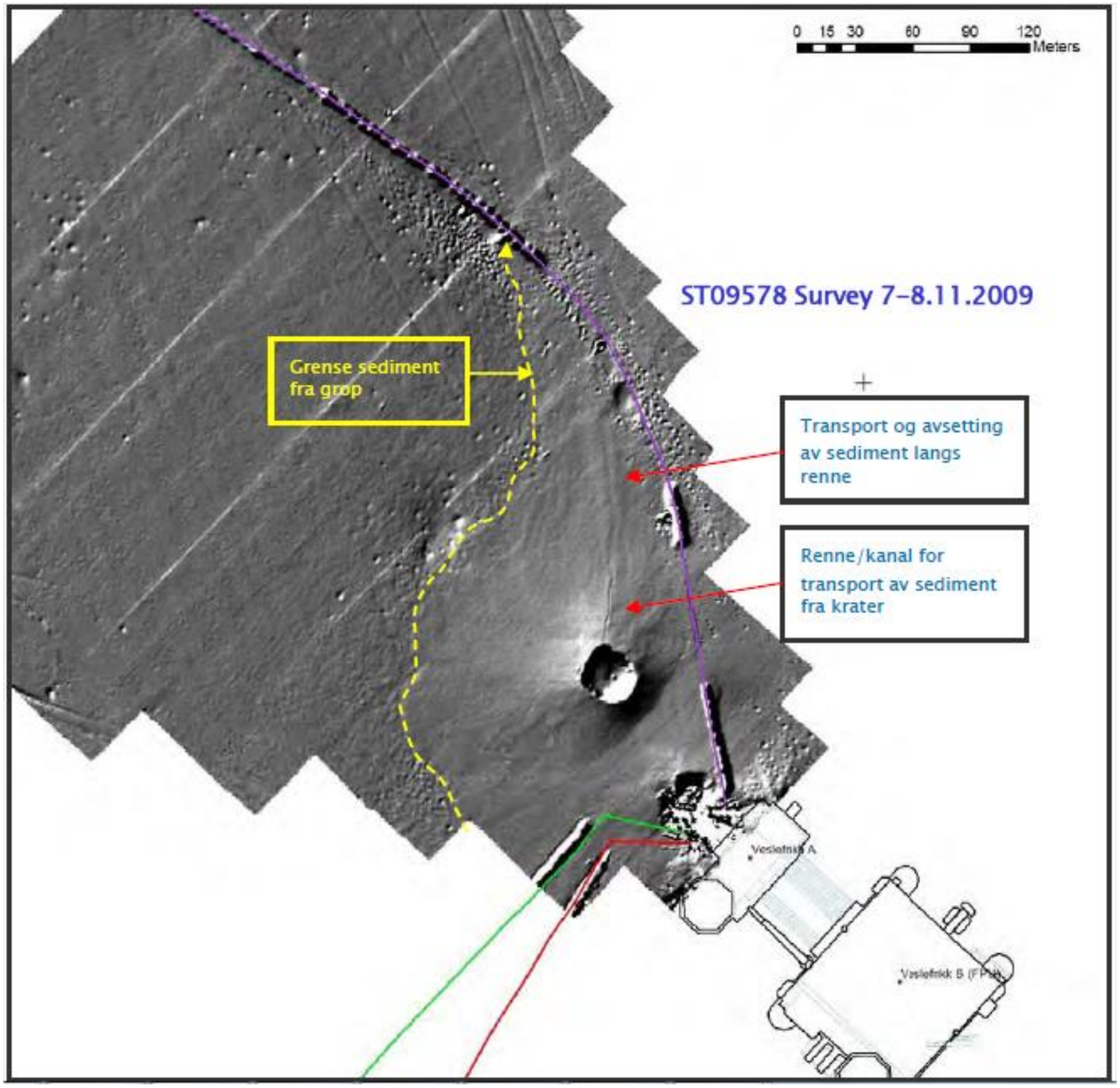


Fig. 4.9: Pits and accumulation of sediments on the seabed (seen from above) detected after the Veslefrikk incident (Statoil 2010).

Background Information

The 30/3-A-23 A well is a production well with drill cuttings re-injection in the C-annulus (20 x 13 3/8"). Since 1997 milled drill cuttings and slop had been injected into this part of the annulus (Fig. 4.10). The annulus was also used for injection of fluids, mostly oil containing water, from the closed-drain system at Veslefrikk A and Veslefrikk B under shutdowns, with a separate pump and line into the CRI-line. Additionally residues from the separators had been pumped from closed drain at Veslefrikk B to closed drain at Veslefrikk A and further on down to the 30/3-A-23 A C-annulus during shutdowns.

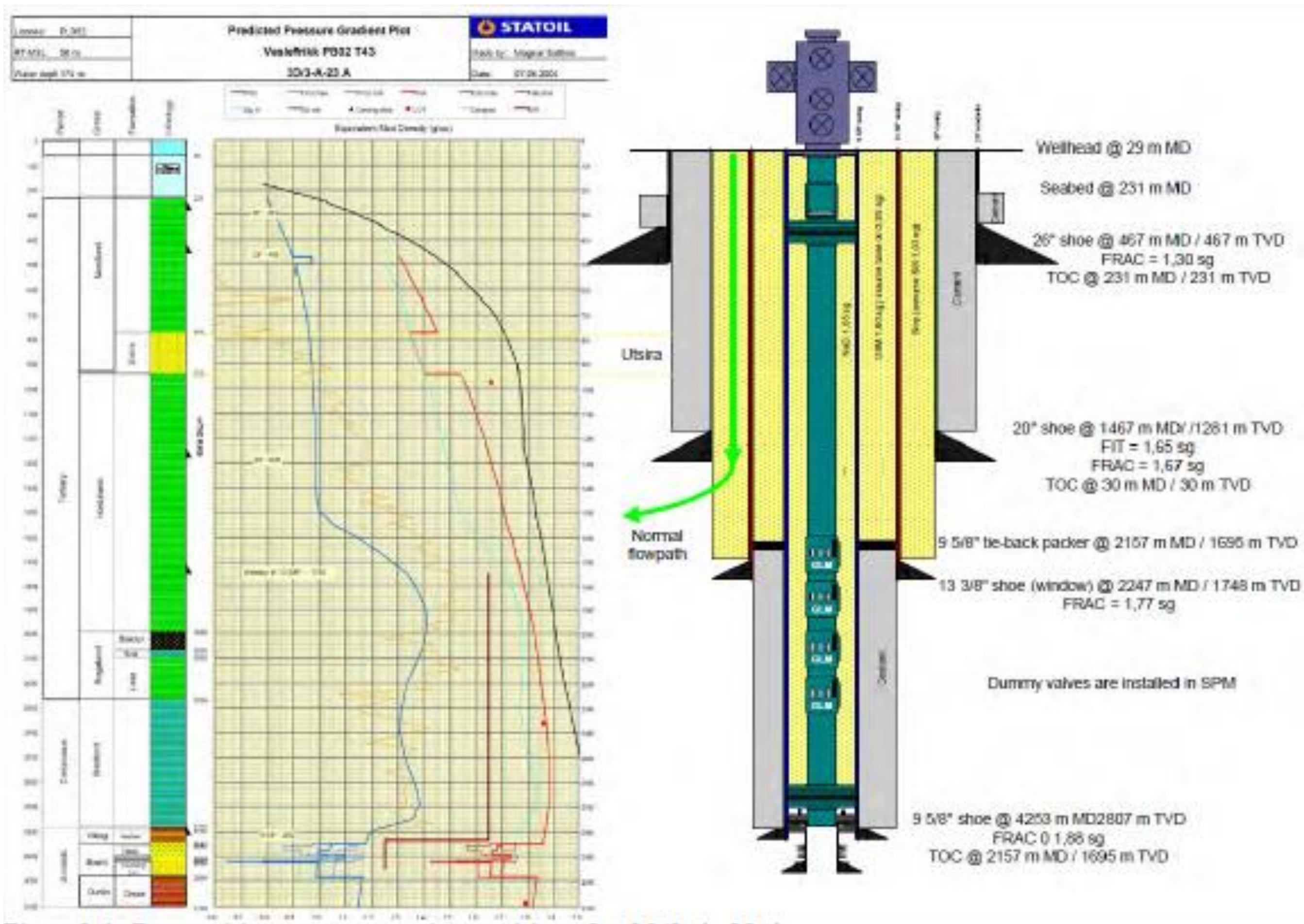


Fig. 4.10: Pore pressure prognosis (left) and outline for well 30/3-A-23 A (right) (Statoil 2010).

The 20" casing shoe was put at 1467 m MD/ 1281 m TVD in the Hordaland Group. The concept behind the injection by the 20" shoe was the fractures in the impermeable clay sequence growing up to the Utsira formation were the liquid was supposed to "bleed off". The good permeability and matrix-leakage from the Utsira formation should work as a barrier for further fracturing towards the seabed. Fig. 4.11 demonstrates the concept behind the injection.

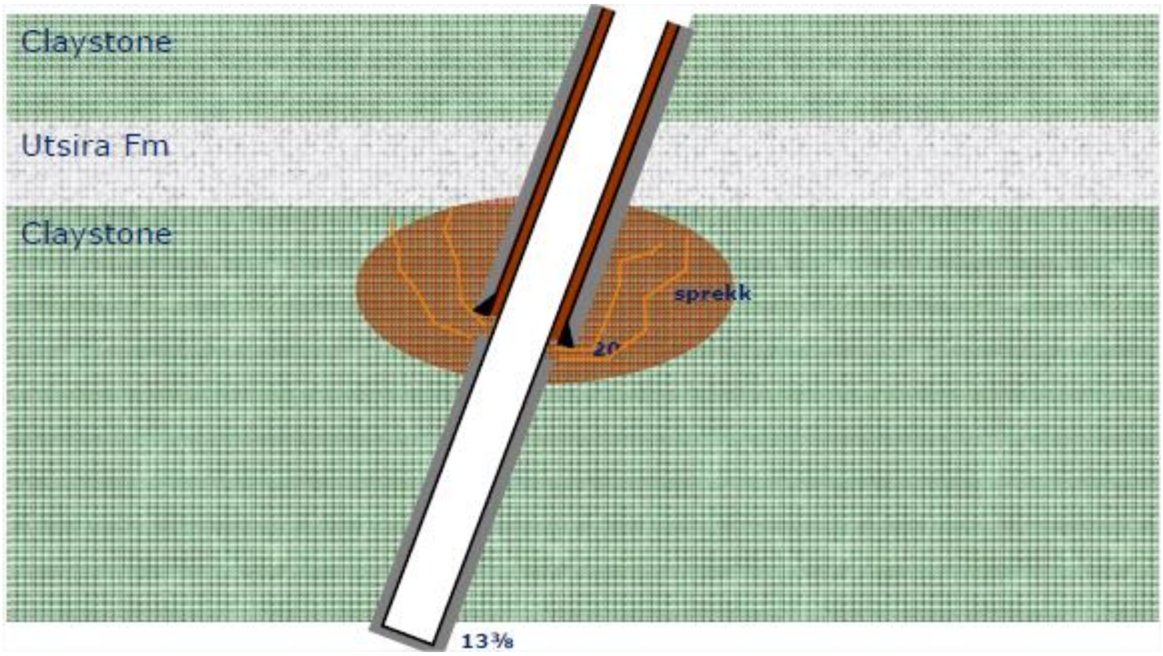


Fig. 4.11: Outline of cuttings injection by the 20" casing shoe set under the target sand (Statoil 2010).

The main concept was that the fractures induced by each injection sequence did not grow through the Utsira formation, but bled the liquids off when they reach the bottom of the formation. The Utsira formation above the 30/3-A-23A well had such a high permeability that they thought it was impossible to propagate fractures, due to fluids being absorbed (matrix flow) and the pressure consequently bled off.

The C-annulus was not included in the primary or secondary well barrier envelope towards production reservoir. A pressure gauge was installed in the C-annulus and the pressure was measured manually. The pump pressure wass measured while injecting cuttings/slop with the rig pumps.

Formation Description

The formation over the injection point at 1281 m TVD can be divided into three main parts:

1) The Hordaland Group: The Hordaland Group lies approximately 1000 meter below the Utsira Formation. It is formed in early to late Tertiary (5-55 mill. Year). The upper part of the group is mainly unconsolidated gray clay with some thicker silt layers. The Hordaland Group has marine deposits at 100-300 m depth. A number of polygonal faults are observed in the group.

2) The Utsira Formation (Lower Nordland Group): The Utsira Formation at Veslefrikk is approximately 160 meter thick (from well 30/3-A-23 A) and consists of unconsolidated sand. Fine sand is dominating this part of the formation. In some areas clay lenses can occur.
3) The Nordland Group: The formation over the Utsira Formation (at 775 m to seabed) is dominated by clay stone with some thin sand layers. The formation is unconsolidated, but can in some zones (down to approx 400 m TVD MSL) be over consolidated due to the Quaternary glaciations. It also contains some drop rocks from icebergs and pack ice. No faults are observed in the Nordland Group. Shallow gas was observed in a 2-4 m thick sand zone at approximately 440 m TVD MSL over large parts of the field. The pore pressure in this sand zone is between 1.07-1.10 sg EMW. A 26" conductor at 30/3-A-23 A was placed 10 m over this shallow gas zone.

Well Design

The cement quality in the 24" hole behind the 20" casing was not logged, but the cement job was executed with a full return of the cement. The top cement was set by 30 m TVD RKB (by the wellhead). The well inclination was 52° by the 20" shoe, 33° by 933 m TVD RKB (bottom of the Utsira Formation), 21° by 755 m TVD RKB (top of the Utsira Formation) and approximately 8° by the 26" shoe. 2 centralizers/joint is set at the bottom 10 casing-joint (up to ca. 1347 m MD/1210 m TVD RKB) as well one centralizer/joint on the 8 joints under and the 4 joints over the Utsira Formation. In other words; no centralizers are set in the interval over the Utsira Formation where the angle of the well is between 21° and 33°. This may have lead to an increased risk of poor displacement of mud on the lower side and/or channeling with free water on the upper side in the interval which again may leave a migration path passing the Utsira Formation.

The quality on the cement layer around the casing is summarized in Fig. 4.12. It is concluded that the area from 968 m MD up to the 26" shoe had a potential for poor cement. The middle part in this area is assumed to be the weakest point because of the missing centralization and poor cement slurry properties. The cement quality in the upper and lower part of the well is considered as so that a continuous channel/failure of the cement along the entire well is considered as very unlikely.

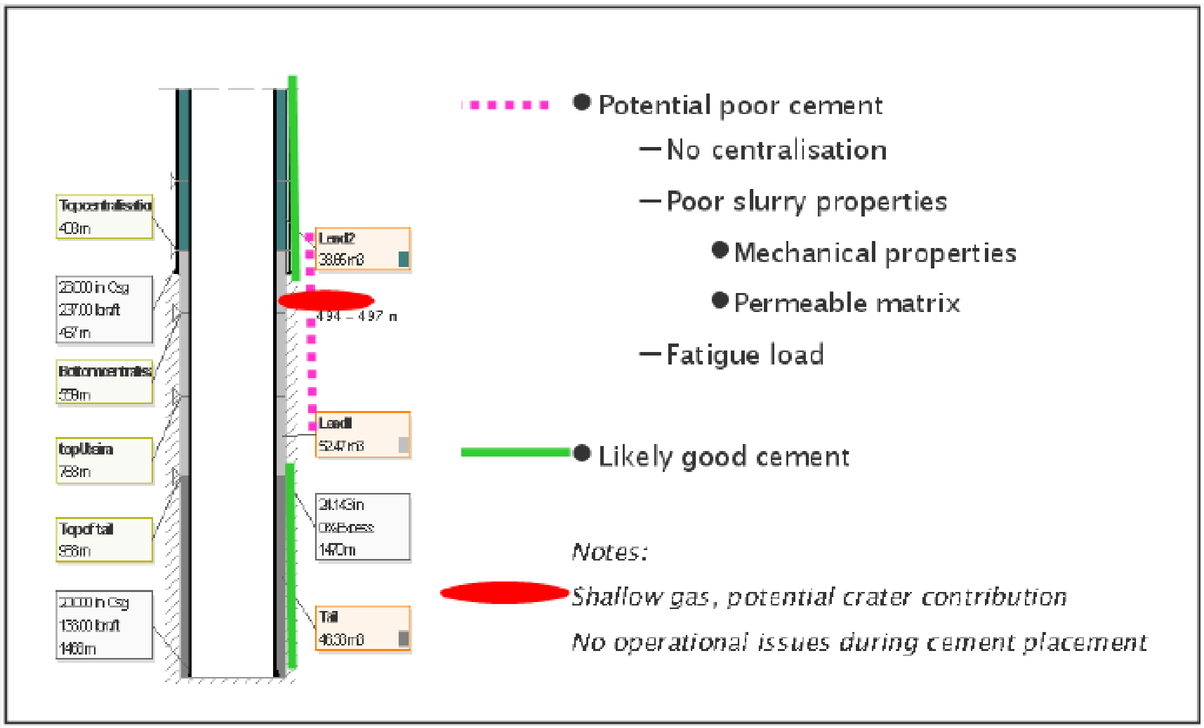


Fig. 4.12: The initial cement layer quality around the casing (Statoil 2010).

The cement quality around the 20" shoe was demonstrated as god, and the cement job by the 26" shoe would have worked as a barrier for further channel flow. The most likely possibility was therefore channel flow along poor cement in the middle part of the well to a depth of 520-500 m TVD RKB (depending on the flow rate) and that the injection would have continued as fractures in the overburden. This calculation was based on the observed pump pressure at 23 bars and an assumed friction loss on 10 bar together at 1000 lpm. This gave a net fracturing pressure at about 20 bars. The minimum effective horizontal stress was 20 bar at a depth on 500 m TVD RKB, demonstrated in Fig. 4.13:

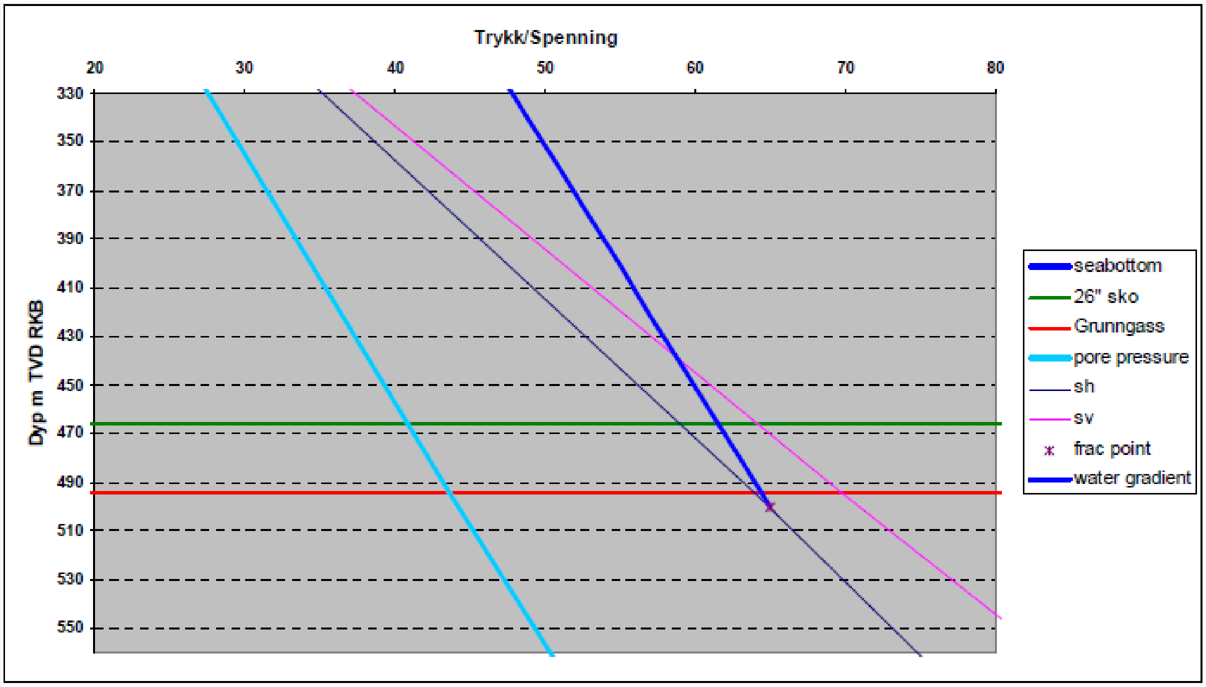


Fig. 4.13: Demonstrating the horizontal (sh)- and vertical (sv)-stress profiles, as well as a hydrostatic water column from the point where the horizontal stress equals corrected pump pressure (Statoil 2010).

Fig. 4.13 demonstrates that fracturing in the overburden could be conducted by a depth of 500 m TVD RKB. This was the area with no centralization in the 20" casing, and it laid in the shallow gas zone. It was therefore possible that the leak also had taken shallow gas with it as the fracture propagated to the seabed. The shape of the seabed erosion pits might have been created from the discharge of the cuttings/slop and insertion of the slope. Shallow gas can also have contributed to the shape.

Events

The events in conjunction with the incident are described in Table 12.

Table 12: Event summary before leakage detection.

Time	Case Observations
dec.97	Pump pressure decrease from 85 to 25 bar under injection
dec.97	Stable low injection pump pressure at 25 bar
jan.06	Still stable low injection pump pressure
jan.06	A strategist test concludes with good injectivity in the 30/3-A-23 A Well. The report confirms the low injection pressure, but did not disallow the well as an cuttings injection well
01.11.2008	DWB PDNS VF became aware of the low injection pressure
01.11.2008	Rock mechanics advises together with DWB PDNS VF to terminate the cuttings injection in well 30/3-A-23 A due to leakage suspicions
01.11.2008	Developed a test program for the cuttings injectors. No testing were conducted.
27.10.2009	Observation of pits on seabed with ROV inspection
27.10.2009	Poor visibility on seabed
05.11.2009	Observation of Oil/Gas in the Pit by C3
05.11.2009	Reservoir injectors were sequentially shut down, as well as production in well 30/3-A-23-A and drilling in well 30/3-A-1 AY1
05.11.2009	No effect on the activity in the pit
06.11.2009	Identified a 10 m deep pit by one of the legs (C3) at Veslefrikk A. Small black drops came up from the pit
08.11.2009	All activity by leg C3 had stopped.
08.11.2009	The pit 65 m northwest from leg C3 was identified with activity, as well as two other pits 1000 m from Veslefrikk A. No activity in the new pits.
11.11.2009	Seabed mapping reveals 13 new pits in a radius of 500 m around Veslefrikk A. The Seabed mapping also shows accumulation of sediments around the pit 65 m northwest of leg C3. Very likely that sediments were transferred from a channel/crack central in the pit
11.11.2009	Gas/oil bubbles observed coming from pit 65 m northwest of leg 3.

Causes of the Incident

Causes of incidents can be divided in two parts; triggering causes and underlying causes. A triggering cause is defined as an unfortunate/dangerous action or condition that triggered one or more individual events. An underlying cause is defined as an event or circumstance that is present before failure occurs, but which in itself does not necessarily lead to the failure (Sintef 2001).

Triggering Causes

The investigation group was unable to establish a definitive triggering cause. Additional mapping and analysis required to do so could not be carried out during the investigation period. Several triggering causes have been considered, and the most likely explanation is:

1. The injection pressure has communicated to intervals under 26” shoe where the cement is poor. Fissures in the formation have formed, either as a result of injection or by faults below the Utsira formation.
2. Poor cement in the interval above the Utsira formation.
    a. No centralization of the 20” casing over the Utsira formation and less robust cement design.
    b. Annular injection well design, in which mechanical loads on the cement can occur in connection with pressure cycles during injection
3. At a depth of about 520 m (above the Utsira formation and below the 26” casing shoe) the injection pressure have resulted in fracturing to the seabed and the formation depressions.

Underlying Causes

The investigation group arrived at the following underlying causes:

1. Inadequate understanding of risk and potential hazards, including weaknesses associated with well design, cement quality, location of the injection point, interpretation of pressure response and potential consequences.
2. Weaknesses in well design.
3. Deficient procedures/requirements.

4. Unclear responsibilities.
5. Deficient expertise and training.
6. Poor transfer of experience.

Concept Summary from the Well 30/3-A-23-A, Veslefrikk Incident

Table 13 lists the symptoms and errors detected before and during the 30/3-A-23- A, the Veslefrikk A incident.

Table 13: Symptoms and errors observed, and their placement in the ontology structure. New concepts are highlighted in bold.

Concept	Position in the ontology
Re-Injecting Cuttings	**Activity**
Seabed Erosion Pit	**Parameter**
Poor Visibility on Seabed	**Parameter**
Hydro Carbon Emissions To Sea	**Parameter**
Abnormal Decline In Injection Pressure	**Parameter**
Poor Centralized Pipe	Parameter
Shallow Gas Bearing Formation	Parameter
Inattentive To Warning Signs	**Human Error**
Underestimating Situation	**Human Error**
Inadequate Well Design	**Human Error**
Poor Cement Design	**Human Error**
Deficient Transfer And Reuse Of Experience	**Human Error**
Unclear Responsibility	**Human Error**

4.2Expansion of the DrillKM on Basis of Case Information

New concepts make the DrillKM grow. By embedding the new concepts from each case-observation a more complete model evolves, as Fig. 4.14 and Fig. 4.15 demonstrates. While new concepts are being placed into the subclasses, similar concepts evolves in the investigators mind. By implementing the concept High Well Inclination, new concepts such as Low Well Inclination and Changing Well Inclination evolves at the same time. These are not implemented in the concept tabled in previous chapters, but still marked with red color in the figures, to demonstrate the expansion of the model.

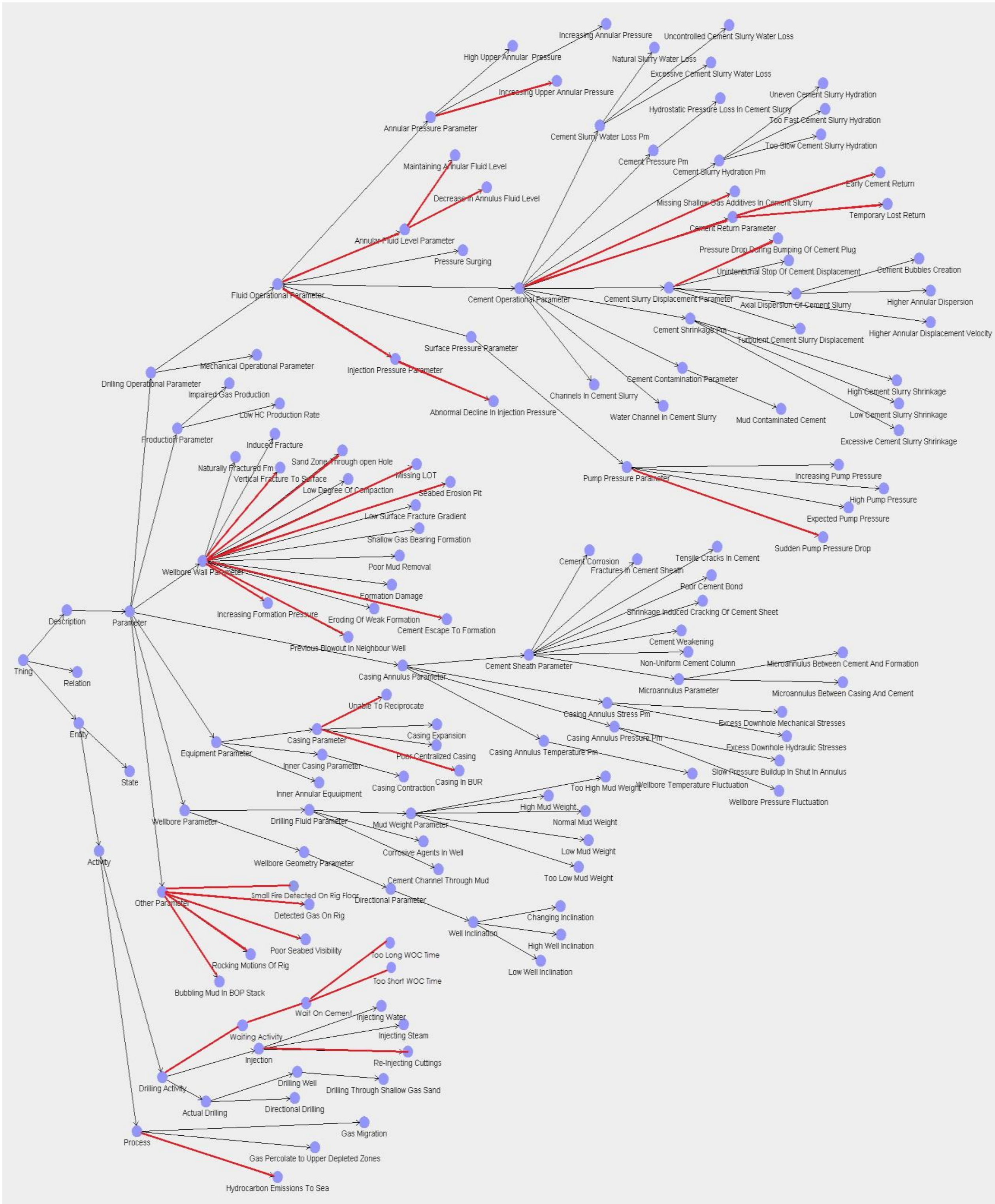


Fig. 4.14: Example of the subclasses Parameter, Process and Activity, structured into subclasses of cementing related concepts interconnected through the relation "has subclass". New concepts are marked with red color.

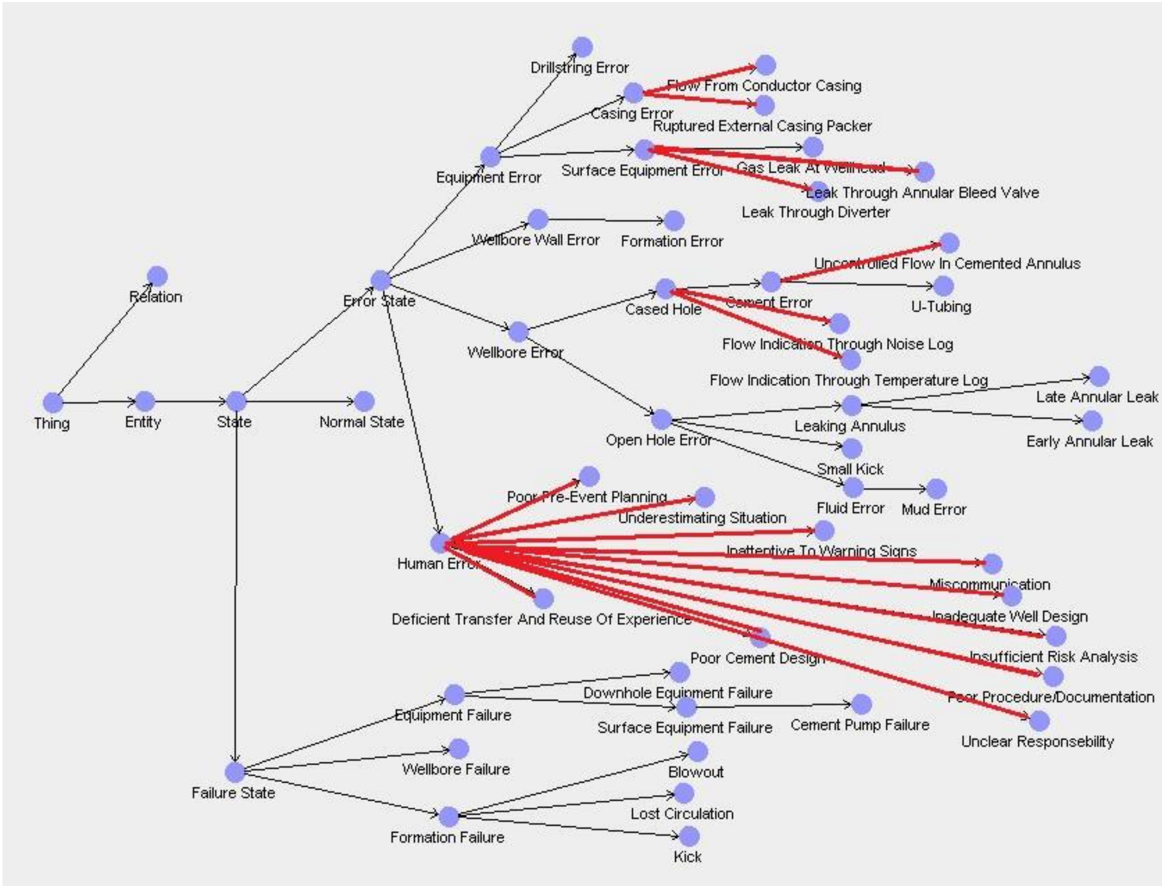


Fig. 4.15: Failure- and error state of the cementing process. New concepts are marked with red color.

5 The New Models to Find the Failure Cause

5.1 Derived Symptoms from the Case Study

To detect errors or failures by use of the knowledge model, deviation from normal behavior (symptoms) somehow have to be registered and entered into it. There are mainly three different ways to this:

1. Data agent, e.g. logging tools, resulting in on-line findings automatically entered into the knowledge model.
2. Known static information, e.g. from well planning or earlier experience from neighbor wells. These symptoms can be implemented as observations/symptoms before the operation starts.
3. Manually entered observations during the operation.

In this report there will also be a fourth way to implement data:

4. Post incident

The post incident implementation way is not possible to use during operations, but is here used to help qualifying the cases and make the analysis more comprehensive. An example is Poor Pre-Event Planning, which is just possible to discover after an event have occurred.

Table 14 exemplifies the relevant symptoms/observations of Case 1 and how they are entered into the DrillKM. These are the concepts which in the next subchapter will be used to derive relationships from and thus expand the DrillKM. This case represents the methodology of expanding the model. Exactly the same was repeated for 4 more cases, and the resulting case observations are presented in Appendix B.

Table 14: Observed symptoms after the fact, Case 1.

Previous Blowout In Neighbor Well	Static info
Missing LOT	Static info
Shutting In Diverter	Manual input
Increasing Annular Pressure	Manual input
Flow From Conductor Casing	Manual input
Detected Gas On Rig	Manual input
Rocking Motions Of Rig	Manual input
Poor Pre-Event Planning	Post Incident

5.2 Relationships from the Symptoms

Symptoms noticed before and during the incident are related to the failure, either directly or through longer paths. As previously mentioned, the relation type for each strength value can be defined as direct relation or inverse relation. The relations 'causes' and 'caused by' are examples of direct and inverse relations, and has in this thesis the strength value 0.7 as a default value in order to simplify the model and analysis. Examples of entities, relations, relation strengths and relationships found in Case 1 are presented in Table 15. The table is a section of the complete table of Case 1 found in Appendix C, and demonstrates how the model works.

By organizing all concepts into tables as demonstrated below, the process of structuring the entities into hierarchies, as shown in Chapter 5.3, will become clearer.

Table 15: A few relationships from entities found in Case 1.

Entity	Relation	Strength	Target entity
Previous Blowout In Neighbor Well	causes	0.7	Shallow Gas Bearing Formation
Shallow Gas Bearing Formation	causes	0.7	Drilling Through Shallow Sand
Drilling Through Shallow Sand	causes	0.7	Low Degree Of Compaction
Low Degree Of Compaction	causes	0.7	Low Surface Fracture Gradient
Low Surface Fracture Gradient	causes	0.7	Naturally Fractured Formation
Low Surface Fracture Gradient	causes	0.7	Induced Fracture
Lost Circulation	caused by	0.7	Naturally Fractured Formation
Lost Circulation	caused by	0.7	Induced Fracture
Shutting In Diverter	causes	0.7	Increasing Formation Pressure
Shutting In Diverter	causes	0.7	Increasing Upper Annular Pressure
Shutting In Diverter	caused by	0.7	Uncontrolled Flow In Cemented Annulus
Induced Fracture	caused by	0.7	Increasing Formation Pressure
Induced Fracture	caused by	0.7	Low Surface Fracture Gradient
Induced Fracture	caused by	0.7	Wrong Fracture Pressure Assumption
Induced Fracture	causes	0.7	Vertical Fracture To Surface
Induced Fracture	causes	0.7	Lost Circulation
Missing LOT	causes	0.7	Wrong Fracture Pressure Assumption
Increasing Annular Pressure	caused by	0.7	Gas Migration
Flow From Conductor Casing	caused by	0.7	Gas Migration

5.3 Five cases, from symptom to failure

The related concepts from all cases presented in Appendix C are in this subchapter modelled and presented in structural hierarchies with cause-effect paths leading from observations to failures. The arrows represents the relations ‘causes’ or ‘caused by’ which has the path strength 0.7.

Each structural hierarchy presented below is subdivided into five parts; observed symptoms, symbolic concepts, errors, target errors and failures, in order to clarify what the main causes of the failures are. The concepts in the error section does not necessarily have an error subclass in the DrillKM, but is here used to demonstrate the causes behind the target errors leading to failure.

Fig. 5.1 exemplifies a structural hierarchy of the observations/symptoms from Case 1, and how they lead to the relevant errors, target errors and failures. We see that Blowout and Lost Circulation is identified as the most probable failures of the incident. Vertical Fracture To Surface, Uncontrolled Flow In Cemented Annulus and Leak Through Diverter is identified as target errors, while Naturally Fractured Formation, Induced Fracture, Gas Migration and Cyclic Diverter Fatigue is identified as errors leading directly or indirectly to the failures. The figures below just gives an impression of which failures and failure causes are the most probable. Calculations presented in Chapter 5.4 and 6 will reveal the definitive probability percent.

When experiencing leaks through the cement sheath while drilling in shallow depths, Blowout and Lost Circulation are logically resulting failures. The observations will be expected to mainly point towards these two failures.

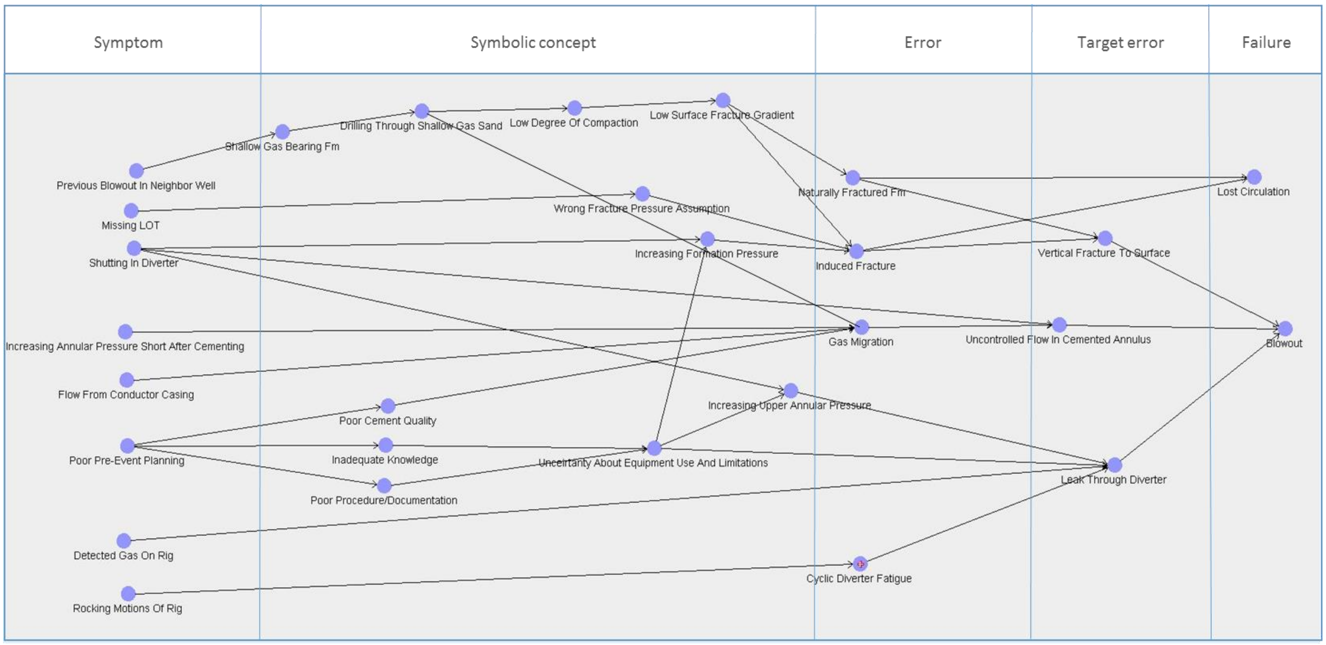


Fig. 5.1: The path of all observations and derived symptoms (left) from Case 1, leading to relevant error concepts and target errors. All observations are leading to the failures Blowout and Lost Circulation (right).

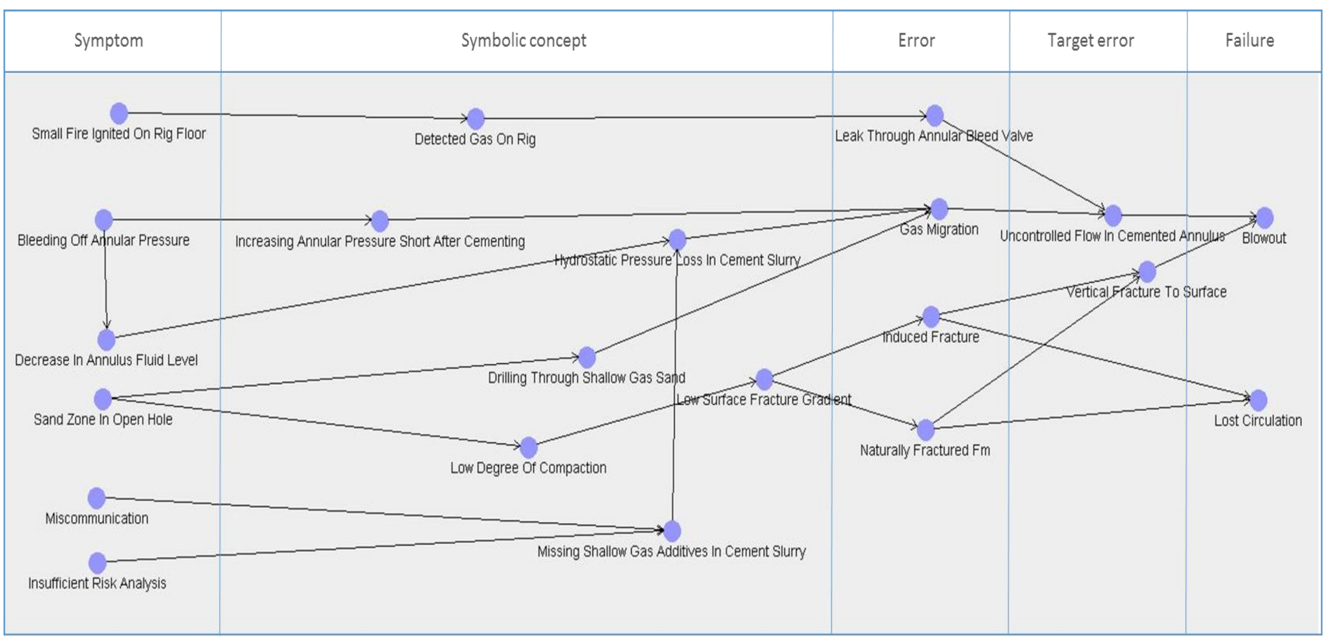


Fig. 5.2: The path of all observations and derived symptoms (left) from Case 2, leading to the failures Blowout and Lost Circulation (right).

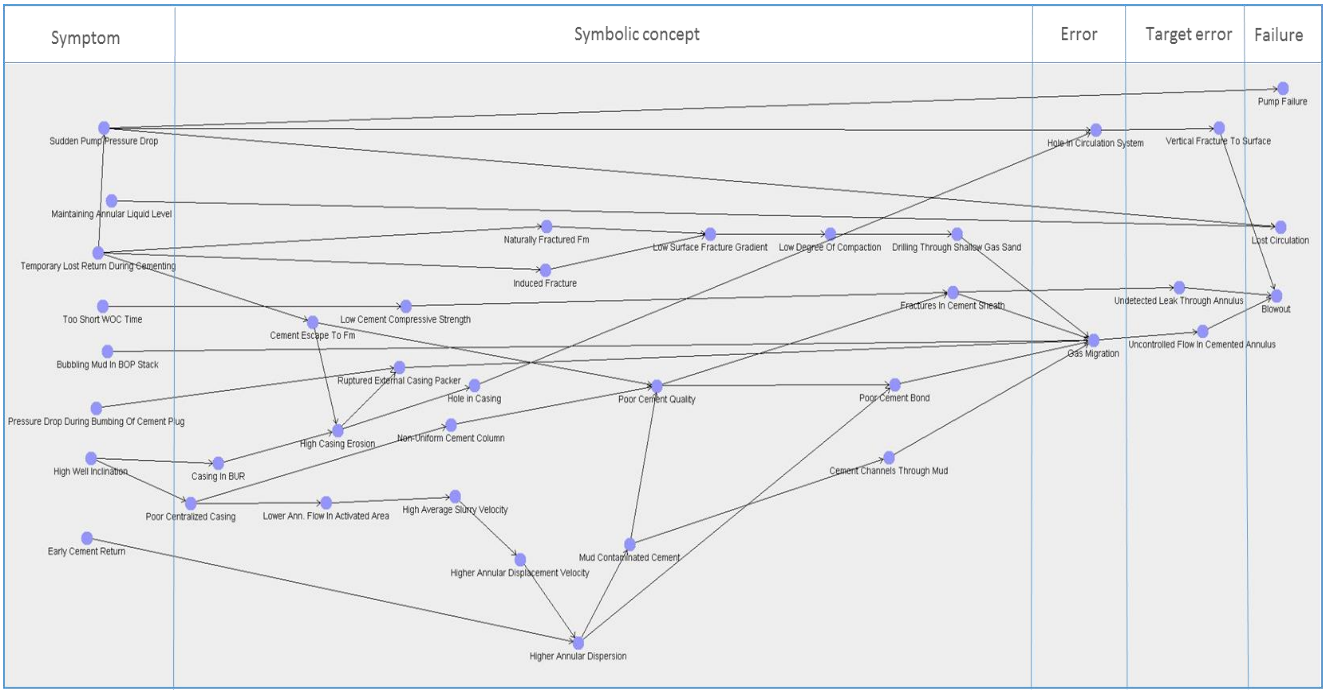


Fig. 5.3: The path of all observations and derived symptoms (left) from Case 3, leading to the failures (right) Blowout and Lost Circulation, except one (the top one).

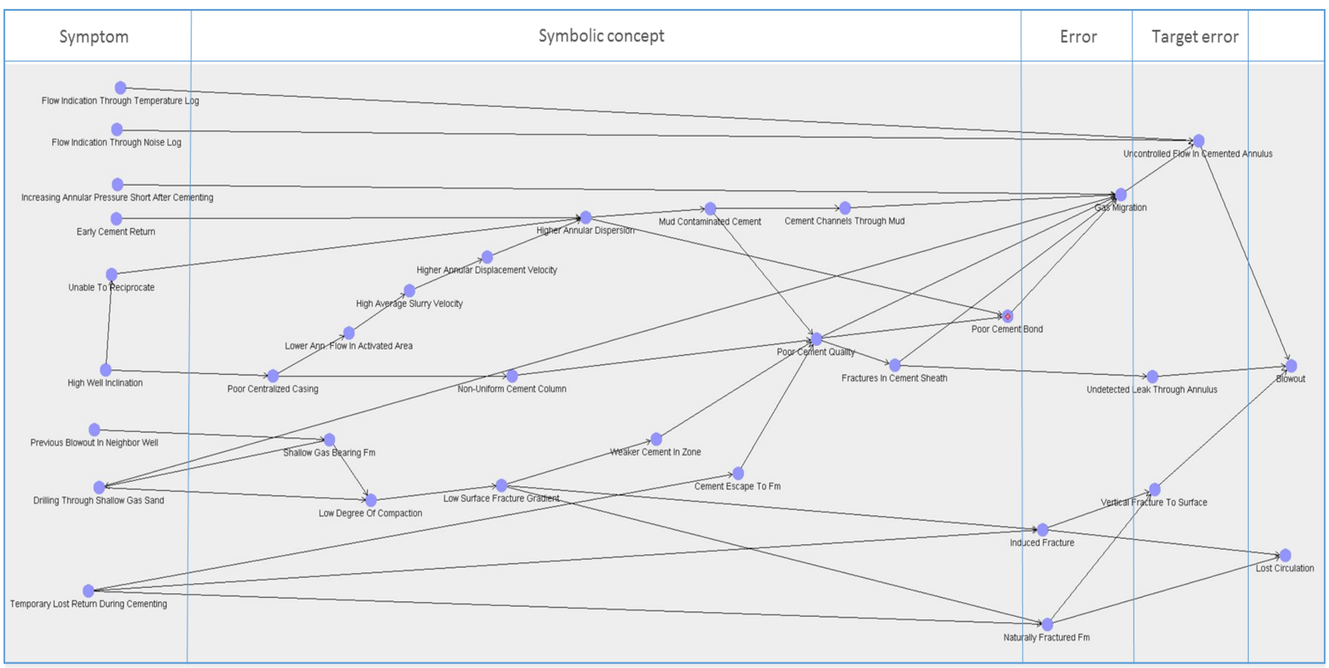


Fig. 5.4: The path of all observations and derived symptoms (left), leading to the relevant error- and target error concepts in Case 4. All observations are leading to the failures Blowout or Lost Circulation.

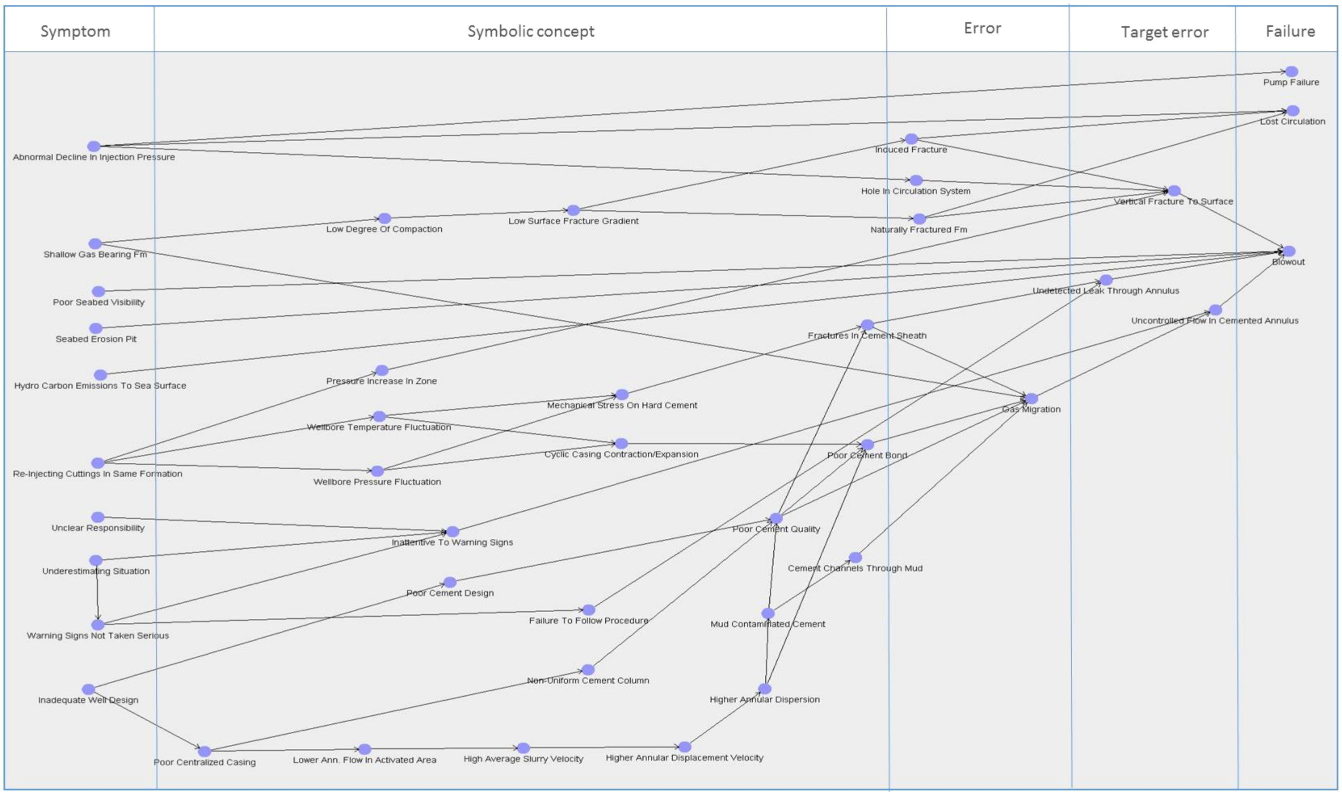


Fig. 5.5: The path of all observations and derived symptoms (left), leading to relevant error- and target error concepts in Case 5. All observations are leading to the failures Blowout or Lost Circulation, except for one (the top one).

5.4 Calculations in Terms of Failure Probability

To demonstrate the methodology, Case 1 was selected. The paths from the 8 observations lead with different path strengths to the failure concepts. Using equations 2.1 and 2.2 presented in Chapter 2.3 the path strength and explanation strength of each single path is possible to calculate. A more detailed approach for all cases is found in Appendix D.

Table 16 presents the resulting explanation strengths of the observations from Case 1. The explanation strength of all observations pointing to Blowout are 3.47, thus translating the explanation strength to 3.47/5.05 * 100% = 68.8 % of all observations. The explanation strength of all observations pointing to Lost Circulation are 1.58, thus translating the explanation strength to 1.58/5.05 * 100% = 31.2 % of all observations.

Table 16: Results after testing Case 1 by means of DrillKM.

Failure	Explanation Strength	Probability [%]
Blowout	3.47	3.47 / 5.05 * 100% = **68.8**
Lost Circulation	1.58	1.58 / 5.05 * 100% = 31.2
Total	5.05	100.0

The results of the failure calculations of all cases are summarized in Table 17. In the other four out of five cases Blowout and Lost Circulation was, as expected, pointed out as the main failures, with different degrees of probability. In all cases Blowout has the highest failure probability, which corresponds well with what actually happened in all cases.

Table 17: Resulting failure calculations from all cases. Blowout is by far the most probable failure cause.

Case number	Failure	Probability [%]
1	**Blowout** Lost Circulation	**68,8** 31,2
2	**Blowout** Lost Circulation	**78,9** 21,1
3	**Blowout** Lost Circulation Pump Failure	**62,4** 25,1 12,5
4	**Blowout** Lost Circulation	**77,8** 22,2
5	**Blowout** Lost Circulation Pump Failure	**78,2** 13,7 8,1

6 Evaluation and the Search for the Failure Explanation

The goal of this study was to develop a knowledge model and reveal the cause behind leaks in cemented annuli. The results presented in Chapter 5.4 reveals Blowout and Lost Circulation as the two most obvious failures. By stepping one level back in the DrillKM we are able to find which errors are pointing strongest towards the failures. The results presented in this chapter are small sections of the more detailed calculations found in Appendix E and F.

The calculated results from Case 1 (Table 18) reveals the experienced problem with the diverter as the target error which led to the main failure Blowout. Uncertainty about use and limitations when shutting in the diverter resulted in a pressure increase in the upper annular region which were greater than the flowline seals capacity to maintain. This, and a possible cyclic fatigue on the diverter, probably resulted in a leak.

Table 18: Target errors directly leading to failures in Case 1, their explanation strength and probability.

Target error	Explanation Strength	Probability [%]	Resulting failure
Vertical Fracture To Surface	1.26	20.5	Blowout
Uncontrolled Flow In Cemented Annulus	2.02	33.0	Blowout
Leak Through Diverter	2.85	**46.5**	Blowout
Total	*6.13*	*100.0*	

Table 19 reveals the main errors leading directly or indirectly to the failures. Gas migration through the cement slurry is calculated to be the main contributing cause to the target errors. The gas migration eventually evolved into an uncontrolled flow through the cemented annulus, which led to the decision to shut in the diverter.

The second most probable error, Induced Fracture, is caused by the increasing pressure on the formation resulting from the diverter shut-in. The formation was not leak-off tested, and the fracture pressure was thus unknown. The fact that blowouts due to shallow gas had occurred in the same formation at an earlier point, indicates a danger of drilling through a shallow sand zone containing gas and which also might have a low fracture pressure due to the low compaction. The induced fracture of the formation may have led to lost circulation or it may have propagated to the surface and caused the blowout.

Table 19: Errors leading to the target errors in Case 1, their explanation strength and probability.

Error	Explanation Strength	Probability [%]	Resulting failure
Naturally Fractured Fm	0.17	3.4	Lost Circulation
Induced Fracture	1.84	37.2	Lost Circulation
Gas Migration	2.23	**45.2**	Blowout
Cyclic Diverter Fatigue	0.70	14.2	Blowout
Total	*4.94*	*100.0*	

Table 20 reveals the concept Uncontrolled Flow In Cemented Annulus as the most probable cause of the blowout in Case 2. The flow was most probably caused by gas migration through the cement slurry, as Table 21 indicates. The fact that shallow gas additives was not mixed into the slurry and the fact that a shallow gas sand was penetrated created perfect conditions for the gas to start flowing through the slurry. By opening the annular bleed valve when bleeding off the increasing annular pressure, the annular fluid level decreased and a hydrostatic pressure loss in the slurry occurred. This enabled even more gas to flow from the shallow gas zone which led to loss of control.

Table 20: Target errors leading to the failures in Case 2, their explanation strength and probability.

Target error	Explanation Strength	Probability [%]	Resulting failure
Uncontrolled Flow In Cemented Annulus	2.09	**81.3**	Blowout
Vertical Fracture To Surface	0.48	18.7	Blowout
Total	*2.57*	*100.0*	

Table 21: Errors leading directly or indirectly to the failures of Case 2, their explanation strength and probability.

Error	Explanation Strength	Probability [%]	Resulting failure
Leak Through Annular Bleed Valve	0.49	13.3	Blowout
Gas Migration	2.50	**68.0**	Blowout
Induced Fracture	0.34	9.3	Lost Circulation
Naturally Fractured Fm	0.34	9.3	Lost Circulation
Total	*3.68*	*100.0*	

The most probable cause of the blowout in Case 3 was, according to the calculations, an uncontrolled flow through the cemented annulus (Table 22). This flow was most probably caused by gas migration, as the results in Table 23 demonstrates.

Table 22: Target errors leading to the failures in Case 3, their explanation strength and probability.

Target error	Explanation Strength	Probability [%]	Resulting failure
Vertical Fracture To Surface	1.24	26.1	Blowout
Undetected Leak Through Annulus	0.96	20.2	Blowout
Uncontrolled Flow In Cemented Annulus	2.55	**53.7**	Blowout
Total	*4.75*	*100.0*	

The fact that the well inclination was rather high might have caused the casing to be improper centralized. This may have caused axial dispersion of the cement slurry, which materializes as early return of the cement seen at the surface. Axial dispersion causes poor cement bonding to the wellbore wall, and thus leaves a route for gas to migrate. It also increases the chance of mud contamination of the cement, which leads to poor cement quality and poor bonding.

The high well inclination have placed the casing in the buildup rate (BUR) of the well. A high buildup rate increases the chances of erosion on the casing and the External Casing Packer (ECP). This is due to the placement of the drillstring against the casing, as it will place itself in the upper part of the well when the inclination is high. When the drillstring rotates, it will at the same time erode the casing. An observed pump pressure drop indicates a hole in the circulation system which might have induced a fracture to the surface and thereby caused the blowout. The sudden pump pressure drop may also have resulted from some kind of pump failure or by lost circulation, but because blowout stands out as the most probable failure a hole somewhere in the circulation system is the most probable cause.

Table 23: Errors leading directly or indirectly to the failures of Case 3, their explanation strength and probability.

Error	Explanation Strength	Probability [%]	Resulting failure
Hole In Circulation System	1.43	29.9	Blowout
Gas Migration	3.35	**70.1**	Blowout
Total	*4.78*	*100.0*	

The target error calculations of Case 4 in Table 24 reveals the concept Uncontrolled Flow In Cemented Annulus as the most probable cause of the failure. As Table 25 shows, the most probable cause of the target errors was gas migration through the cement slurry. Shortly after cementing an increasing annular pressure was observed, indicating gas flowing in the annulus. The fact that reciprocation was impossible due to the high well inclination, and the fact that early cement return was observed, indicates high annular slurry dispersion when pumping the cement. This may have led to gas migration through poor cement bonding, either directly or indirectly, mud contaminated cement and/or poor cement quality.

Table 24: Target errors leading to the failures of Case 4, their explanation strength and probability.

Target error	Explanation Strength	Probability [%]	Resulting failure
Uncontrolled Flow In Cemented Annulus	6.37	**70.1**	Blowout
Undetected Leak Through Annulus	1.16	12.8	Blowout
Vertical Fracture To Surface	1.55	17.1	Blowout
Total	*9.08*	*100.0*	

Table 25: Errors leading directly or indirectly to the failures of Case 4, their explanation strength and probability.

Error	Explanation Strength	Probability [%]	Resulting failure
Gas Migration	7.10	**71.0**	Blowout
Induced Fracture	1.45	14.5	Lost Circulation
Naturally Fractured Fm	1.45	14.5	Lost Circulation
Total	*10.00*	*100.0*	

The results from the calculation on Case 5 also reveals the concept Uncontrolled Flow In Cemented Annulus as the main cause of the failure and the concept Gas Migration as the main contributing cause of the failure, as Table 26 and Table 27 shows. The process of re-injecting cuttings into the formation causes temperature- and pressure fluctuations in the wellbore, which might lead to fractures in the cement sheath on a long term. The temperature- and pressure fluctuations also causes the casing to contract and expand in a cyclical term, which causes the casing to pull away from the wellbore wall and thus leave a route for gas to migrate. The injection also leads to a pressure increase in the injection zone which, rather seldom, might induce vertical fractures to the surface.

By not sufficiently using other injection related incidents to learn from, the training and skills of the personnel was not sufficient to understand the risks related to injection into the formation and the symptoms to look for if something did not go according to the plan. The abnormal pump pressure decline in 1997 for injection in well 30/3-A-23 A was for instance ignored, even though the pump pressure of the well 30/3-A-11 B, injecting into the same formation, had a significantly higher normal pump pressure. This was a strong indication of lost circulation somewhere in the well, but little was done to investigate this further. By not taking the warning signs serious and by underestimating the situation that occurred, the undetected leak was allowed to evolve.

Table 26: Target errors leading to the failures of Case 5, their explanation strength and probability.

Target error	Explanation Strength	Probability [%]	Resulting failure
Vertical Fracture To Surface	1.46	20.5	Blowout
Undetected Leak Through Annulus	1.98	27.7	Blowout
Uncontrolled Flow In Cemented Annulus	3.69	**51.8**	Blowout
Total	*7.13*	*100.0*	

The well 30/3-A-23 A was first drilled as an exploration well (30/3 7S), and later renamed and converted into a producer and injection well. The cement used for cementing the middle part of the 20" casing was not suited for injection, but for filling and foundation. The cement in this part of the well did therefore have a lower stress resistance, and the possibility for fractures in the cement was significantly higher. Not applying centralizers above the Utsira Formation was also contributing to poor zonal isolation, as migration paths were formed along the cement so the fluids could communicate between the zones.

Table 27: Errors leading directly or indirectly to the failures of Case 5, their explanation strength and probability.

Error	Explanation Strength	Probability [%]	Resulting failure
Induced Fracture	0.34	7.3	Lost Circulation
Naturally Fractures Fm	0.34	7.3	Lost Circulation
Hole In Circulation System	0.70	14.8	Blowout
Gas Migration	3.34	**70.7**	Blowout
Total	*4.72*	*100.0*	

7 Self-Assessment

Diagnosing a problem correctly will lead to an appropriate treatment and result in efficient repair actions and cost reductions. The result of this analysis is numerical values indicating the most probable cause of the incidents. The value gives the reader an indication of which symptoms to look for when cementing a future well in order to avoid serious incidents.

Quality and Shortcomings of the Model

Each relation in this thesis is based upon my own opinion, supported by my Master study in general and Drilling Engineering especially. The relationship between symbolic concepts is thus the relationship that I deem as the best fit, and will obviously vary from person to person. This may lead to different results of different investigations, depending on who was performing the analysis. This fact may be both an advantage and a disadvantage of the modelling. For instance, if a group of people are set to do the same analysis separately, the different results can be compared and the conclusion may be even stronger. This is not true in my case though since I was the only modeler, but the point is true in general.

In this specific analysis a very simplified version of the knowledge model was used. All possible relations of the concepts have not been examined, just the most obvious or relevant ones. The concepts in the Parameter Entity and how the different parameters relate to each other could have been even more detailed and analyzed more closely. In this area there are many rooms of improvement in which I could have done. At the same time, there are room for more studies in the industry. I will continue to closely follow interesting interrelations in the future.

The relation strength 0.7 is used for all relations, except those who are seldom or very weak. The amount of relationships in the model comprises a decreased amount of relationships to be included in the analysis as well as only one level of subclasses, due to my lack of experience with the model and hands-on experience from cementing operations. The result is a less comprehensive conclusion than a complete knowledge model would have determined, because the conclusions does not point towards every single possible failure, but only the most relevant and obvious ones.

The knowledge model is still under constant development. As new cases are continuously imbedded into the model, it will grow stronger and more precise with time.

Quality of Information Applied

The information applied for this analysis was four investigation reports from the Department of the Interior's Minerals Management Service (MMS) and one investigation report from Statoil. The data included some assumptions regarding the cause of the leak, but not any definitive triggering causes of the incidents. This gave me the opportunity to use the information required for the model as input, analyze the symptoms and determine the cause of the incidents without knowing for sure the conclusion in advance. At the same time these assumptions gave me the opportunity to further build the model by the bottom-up approach.

The reports included some background information about the well, description of the incident, and some information regarding similar incidents. The quality of the information given, especially in the American reports was not very comprehensive, and lacking of detailed information about the formation, drilling program and events on the rig. The lack of detailed information made it challenging to model freely without being influenced by the report authors assumed conclusions and assumptions. It would be beneficial to access the same information as the authors of the investigation reports, and thus access information that the investigative panels might have neglected or not perceived as relevant.

Leaks through the cement sheath seems to be a common error which can contribute to larger accidents. Because these leaks not always result in a large scale accident, accessing a sufficient amount of data regarding these types of incidents has proven to be hard to obtain. It would have been beneficial to also access information regarding small scale leaks through the cement, and thus create an even more nuanced model.

Further Work

If performing the analysis using the knowledge model in its full extent, the analysis would have become more comprehensive. Deeper levels of subclasses would have led to stronger conclusions, and additional relationships which would have made the study more inclusive.

Improvements of the knowledge model are still pending; new symptoms, events and higher quality of existing events will improve the tool. The more paths and the better we can differentiate between symptoms, errors and failures will allow for a more detailed distinguish between apparently similar cases.

Creating a more complete table of symptoms, errors and failures where the method of knowledge modeling is utilized in its full extent should be continued. This would make the determination of the main restriction causes through knowledge modeling more reliable, and the goal of revealing a problem before it occur will become closer.

8 Conclusions

Based on the results and evaluations of the DrillKM and the failure causes, the conclusions are subdivided into the following sections:

Analysis of the Cementing Process and its Challenges

- Cementing issues was selected to be implemented to the DrillKM and tested.
- Five cases of leaks through the cement was available through investigative reports from the MMS and Statoil.
- The analysis of the incidents proved Blowout as the most probable failure in all cases.
- The target error that most likely caused the events was Uncontrolled Flow In Cemented Annulus in four out of five cases.
- The most probable error leading to failures, either directly (strength 0.7) or indirectly (lower strength), was in all five cases Gas Migration.
- If symptoms are put in context with cementing problems, the probability of making a correct diagnosis of a downhole problem increases.

The Model Itself

- A simplified version of the DrillKM has been used to analyze the incidents. Symptoms have been interpreted from the reports and used as input for further building of the model based upon text book knowledge and case specific knowledge.
- The model is relying on only one person's opinion and expertise, and the conclusion would have been stronger if a group of investigators would have analyzed the same incidents and compared their results.
- The created DrillKM determined the restriction causes successfully, compared with the conclusions in the investigative reports.

Translation of the Information Applied into Symbolic Concepts

- Information regarding cement related accidents were hard to access. The quality of the reports found was comprehensive, but lacking of detailed information regarding the surrounding formation, drilling program and events on the rig. If this information would have changed the analysis results remains unknown.
- The data included assumptions and descriptions about causes of the incidents, but with no clear conclusions. This gave the investigator the opportunity to make the analysis without knowing the solution for sure.

Further Work

- Using the model in its full extent, instead of a simplified version, will be more beneficial.
- Continued development of the model by analyzing more cases of restrictions would apply additional relationships and lead to a more comprehensive model. More data will give new symptoms and deeper relationships.

Nomenclature

APD – Application for Permit to Drill

BOP – Blowout Preventer

BUR – Build-Up Rate

Cmt – Cement

DrillKM - Knowledge Model of Oil Well Drilling

ECP – External Casing Packer

EMW – Equivalent Mud Weight

ESD - Emergency Shut Down

Fm – Formation

GoM – Gulf of Mexico

HC – Hydrocarbon

HPHT – High Pressure High Temperature

MD – Measured Depth

MSL – Measured Sea Level

NCS – Norwegian Continental Shelf

NPT – Non Productive Time

OCS – Outer Continental Shelf

RKB – Rotary Kelly Bushing

ROV – Remote Operated Vehicle

SEM – Scanning Electron Microscope

TVD – True Vertical Depth

ST – Side Track

WBE – Well Barrier Element

WOC – Wait on Cement

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Appendix

A. All Concepts and Relations

Table 28: All textbook- and case specific concepts and their relations.

Concept 1	Relation	Strength	Concept 2
Gas Migration	causes	0.7	High Annular Pressure At Surface
Gas Migration	causes	0.7	Uncontrolled Flow In Cemented Annulus
Gas Migration	causes	0.7	Increasing Annular Pressure
Gas Migration	causes	0.7	Flow From Conductor Casing
Gas Migration	causes	0.7	Kick
Gas Migration	causes	0.7	Bubbling Mud In BOP Stack
Gas Migration	caused by	0.7	Hydrostatic Pressure Loss In Cement Slurry
Gas Migration	caused by	0.7	Fractures In Cement Sheet
Gas Migration	caused by	0.7	Poor Cement Bond
Gas Migration	caused by	0.7	Drilling Through Shallow Gas Sand
Gas Migration	caused by	0.7	Cement Channels Through Mud
Gas Migration	caused by	0.7	Ruptured External Casing Packer
Gas Migration	caused by	0.7	Poor Cement Quality
Gas Migration	caused by	0.7	Shallow Gas Bearing Formation
Gas Migration	caused by	0.7	Drilling Through Shallow Gas Sand
Gas Migration	caused by	0.7	Microannulus
Gas Migration	caused by	0.7	Water Channel In Cement Slurry
Gas Migration	caused by	0.7	Channel In Cement Slurry
Gas Migration	caused by	0.7	Tensile Cracks In Cement
Hydrostatic Pressure Loss In Cement Slurry	caused by	0.7	Decrease In Annulus Fluid Level
Hydrostatic Pressure Loss In Cement Slurry	caused by	0.7	Missing Shallow Gas Additives In Cement Slurry
Hydrostatic Pressure Loss In Cement Slurry	causes	0.7	Gas Migration
Missing Shallow Gas Additives In Cement Slurry	caused by	0.7	Miscommunication
Missing Shallow Gas Additives In Cement Slurry	caused by	0.7	Insufficient Risk Analysis
Uncontrolled Flow In Cemented Annulus	caused by	0.7	Gas Migration
Uncontrolled Flow In Cemented Annulus	caused by	0.7	Inattentive To Warning Signs
Uncontrolled Flow In Cemented Annulus	causes	0.7	Flow Indication Through Noise Log
Uncontrolled Flow In Cemented Annulus	causes	0.7	Flow Indication Through Temperature Log
Uncontrolled Flow In Cemented Annulus	causes	0.7	Blowout
Uncontrolled Flow In Cemented Annulus	causes	0.7	Shutting In Diverter
Uncontrolled Flow In Cemented Annulus	causes	0.7	Leak Through Annular Bleed Valve
Shutting In Diverter	causes	0.7	Increasing Formation Pressure
Shutting In Diverter	causes	0.7	Increasing Upper Annular Pressure
Detected Gas On Rig	caused by	0.7	Leak Through Annular Bleed Valve
Detected Gas On Rig	causes	0.7	Small Fire Ignition

Poor Cement Bond	caused by	0.7	Higher Annular Dispersion
Poor Cement Bond	caused by	0.7	Poor Cement Quality
Poor Cement Bond	caused by	0.7	Cyclic Casing Contraction/Expansion
Poor Cement Bond	caused by	0.7	High Cement Slurry Shrinkage
Poor Cement Bond	caused by	0.7	Microannulus Between Cement And Formation
Poor Cement Bond	caused by	0.7	Microannulus Between Cement And Casing
Poor Cement Bond	caused by	0.7	Poor Mud Removal
Poor Cement Bond	caused by	0.7	Casing Contraction
Poor Cement Bond	caused by	0.7	Lack Of Roughness Along Cement/Formation
Poor Cement Bond	causes	0.7	Gas Migration
Bleeding Off Annular Pressure	caused by	0.7	Increasing Annular Pressure
Bleeding Off Annular Pressure	causes	0.7	Decrease In Annulus Fluid Level
Low Cement Compressive Strength	caused by	0.7	Too Short WOC Time
Low Cement Compressive Strength	causes	0.7	Fractures In Cement Sheet
Fractures In Cement Sheet	causes	0.7	Undetected Leak Through Annulus
Fractures In Cement Sheet	causes	0.7	Gas Migration
Fractures In Cement Sheet	caused by	0.7	Mechanical Stress On Hard Cement
Fractures In Cement Sheet	caused by	0.7	Low Cement Compressive Strength
Fractures In Cement Sheet	caused by	0.7	Poor Cement Quality
Low Surface Fracture Gradient	caused by	0.7	Low Degree Of Compaction
Low Surface Fracture Gradient	causes	0.7	Induced Fracture
Low Surface Fracture Gradient	causes	0.7	Naturally Fractured Formation
Lost Circulation	caused by	0.7	Induced Fracture
Lost Circulation	caused by	0.7	Naturally Fractured Formation
Lost Circulation	causes	0.7	Abnormal Injection Pressure Decline
Lost Circulation	causes	0.7	Sudden Pump Pressure Drop
Lost Circulation	causes	0.7	Maintaining Annular Liquid Level
Sudden Pump Pressure Drop	caused by	0.7	Drill String Wash Out
Sudden Pump Pressure Drop	caused by	0.7	Hole In Circulation System
Sudden Pump Pressure Drop	caused by	0.7	Pump Failure
Sudden Pump Pressure Drop	caused by		Temporary Lost Return
Vertical Fracture To Surface	caused by	0.7	Induced Fracture
Vertical Fracture To Surface	caused by	0.7	Naturally Fractured Formation
High Well Inclination	causes	0.7	Casing In BUR
High Well Inclination	causes	0.7	Poor Centralized Casing
High Well Inclination	causes	0.7	Unable To Reciprocate
Poor Centralized Casing	causes	0.7	Non-Uniform Cement Column
Poor Centralized Casing	causes	0.7	Lower Ann. Flow In Activated Area
Non-Uniform Cement Column	causes	0.7	Poor Cement Quality
Lower Ann. Flow In Activated Area	causes	0.7	High Average Slurry Velocity
High Average Slurry Velocity	causes	0.7	High Annular Displacement Velocity

High Annular Displacement Velocity	causes	0.7	Higher Annular Dispersion
Higher Annular Dispersion	caused by	0.7	High Annular Displacement Velocity
Higher Annular Dispersion	caused by		Unable To Reciprocate
Higher Annular Dispersion	causes	0.7	Early Cement Return
Higher Annular Dispersion	causes	0.7	Mud Contaminated Cement
Mud Contaminated Cement	causes	0.7	Cement Channels Through Mud
Mud Contaminated Cement	causes	0.7	Poor Cement Quality
Poor Cement Quality	caused by	0.7	Non-Uniform Cement Column
Poor Cement Quality	caused by	0.7	Mud Contaminated Cement
Poor Cement Quality	caused by	0.7	Cement Escape To Formation
Poor Cement Quality	caused by	0.7	Weaker Cement In Zone
Poor Cement Quality	caused by	0.7	Poor Cement Design
Poor Cement Quality	caused by	0.7	Poor Pre-Event Planning
Poor Cement Quality	caused by	0.7	Wrong Assumption During Cement Design
Poor Cement Quality	causes	0.7	Gas Migration
Poor Cement Quality	causes	0.7	Poor Cement Bond
Poor Cement Quality	causes	0.7	Fractures In Cement Sheet
Ruptured External Casing Packer	caused by	0.7	High Casing Corrosion
Ruptured External Casing Packer	causes	0.7	Gas Migration
Ruptured External Casing Packer	causes	0.7	Pressure Drop During Bumping Of Cement Plug
Temporary Lost Return	causes	0.7	Cement Escape To Formation
Temporary Lost Return	causes	0.7	Sudden Pump Pressure Drop
Temporary Lost Return	causes	0.7	Underbalanced Well
Temporary Lost Return	caused by	0.7	Induced Fracture
Temporary Lost Return	caused by	0.7	Naturally Fractured Formation
Cement Escape To Formation	causes	0.7	High Casing Corrosion
Cement Escape To Formation	causes	0.7	Poor Cement Quality
Vertical Fracture To Surface	caused by	0.7	Induced Fracture
Vertical Fracture To Surface	caused by	0.7	Naturally Fractured Formation
Vertical Fracture To Surface	caused by		Hole In Circulation System
Vertical Fracture To Surface	causes	0.7	Blowout
Induced Fracture	caused by	0.7	Increasing Formation Pressure
Induced Fracture	caused by	0.7	Low Surface Fracture Gradient
Induced Fracture	caused by	0.7	Wrong Fracture Pressure Assumption
Induced Fracture	causes	0.7	Vertical Fracture To Surface
Blowout	caused by	0.7	Undetected Leak Through Annulus
Blowout	caused by	0.7	Vertical Fracture To Surface
Blowout	caused by	0.7	Leak Through Diverter
Blowout	caused by	0.7	Kick
Blowout	caused by	0.7	Uncontrolled Flow In Cemented Annulus
Blowout	causes	0.7	Poor Seabed Visibility
Blowout	causes	0.7	Emissions To Sea Surface
Blowout	causes	0.7	Seabed Erosion Pit

Kick	causes	0.7	Increased Instantaneous Pump Pressure
Kick	causes	0.7	Blowout
Kick	causes	0.7	High Mud Gas Content
Kick	caused by	0.7	Underbalanced Well
Kick	caused by	0.7	Low Well Pressure
Kick	caused by	0.7	Gas Migration
Re-Injecting Cuttings	causes	0.7	Pressure Increase In Zone
Re-Injecting Cuttings	causes	0.7	Wellbore Temperature Fluctuation
Re-Injecting Cuttings	causes	0.7	Wellbore Pressure Fluctuation
Pressure Increase In Zone	causes occasionally	0,1	Vertical Fracture To Surface
Cyclic Casing Contraction/Expansion	caused by	0.7	Wellbore Temperature Fluctuation
Cyclic Casing Contraction/Expansion	caused by	0.7	Wellbore Pressure Fluctuation
Mechanical Stress On Hard Cement	caused by	0.7	Wellbore Temperature Fluctuation
Mechanical Stress On Hard Cement	caused by	0.7	Wellbore Pressure Fluctuation
Undetected Leak Through Annulus	caused by	0.7	Failure To Follow Procedure
Undetected Leak Through Annulus	caused by	0.7	Fractures In Cement
Undetected Leak Through Annulus	causes	0.7	Blowout
Leak Through Diverter	causes	0.7	Detected Gas On Rig
Leak Through Diverter	causes	0.7	Blowout
Leak Through Diverter	caused by	0.7	Increasing Upper Annular Pressure
Leak Through Diverter	caused by	0.7	Uncertainty About Equipment Limitation
Leak Through Diverter	caused by	0.7	Cyclic Diverter Fatigue
Rocking Motions Of Rig	causes	0.7	Cyclic Diverter Fatigue
Uncertainty About Equipment Limitation	caused by	0.7	Inadequate Knowledge
Uncertainty About Equipment Limitation	caused by	0.7	Poor Procedure/Documentation
Uncertainty About Equipment Limitation	causes	0.7	Increasing Formation Pressure
Uncertainty About Equipment Limitation	causes	0.7	Increasing Upper Annular Pressure
Uncertainty About Equipment Limitation	causes	0.7	Leak Through Diverter
Deficient Training	causes	0.7	Inadequate Well Design
Inadequate Well Design	causes	0.7	Wrong Assumption During Cement Design
Inadequate Well Design	causes	0.7	Poor Centralized Casing
Deficient Transfer And Reuse Of Experience	causes	0.7	Underestimating Situation
Deficient Transfer And Reuse Of Experience	causes	0.7	Deficient Training
Underestimating Situation	causes	0.7	Inattentive To Warning Signs
Underestimating Situation	causes	0.7	Warning Signs Not Taken Serious
Warning Signs Not Taken Serious	causes	0.7	Inattentive To Warning Signs
Warning Signs Not Taken Serious	causes	0.7	Failure To Follow Procedure

Unclear Responsibility	causes	0.7	Inattentive To Warning Signs
Poor Pre-Event Planning	causes	0.7	Poor Cement Quality
Poor Pre-Event Planning	causes	0.7	Inadequate Knowledge
Poor Pre-Event Planning	causes	0.7	Poor Procedure/Documentation
Shallow Gas Bearing Formation	causes	0.7	Low Degree Of Compaction
Low Degree Of Compaction	causes	0.7	Low Surface Fracture Gradient
Low Degree Of Compaction	caused by	0.7	Drilling Through Shallow Sand
Wrong Fracture Pressure Assumption	caused by	0.7	Missing LOT
Wrong Fracture Pressure Assumption	causes	0.7	Induced Fracture
Low Surface Fracture Gradient	causes	0.7	Induced Fracture
Low Surface Fracture Gradient	causes	0.7	Naturally Fractured Fm
Shallow Gas Bearing Formation	caused by	0.7	Drilling Through Shallow Gas Sand
Shallow Gas Bearing Formation	caused by	0.7	Previous Blowout In Neighbor Well
Shallow Gas Bearing Formation	causes	0.7	Low Degree Of Compaction
Shallow Gas Bearing Formation	causes	0.7	Drilling Through Shallow Gas Sand
Shallow Gas Bearing Formation	caused by	0.7	Sand Indication Through W.L.
High Cement Slurry Shrinkage	causes	0.7	Cement Volume Reduction
High Cement Slurry Shrinkage	causes	0.7	Microannulus
High Cement Slurry Shrinkage	caused by	0.7	Poor Cement Design
Water Channel Through Cement Slurry	caused by	0.7	High Well Inclination
Water Channel Through Cement Slurry	caused by	0.7	High Water Loss In Cement Slurry
Water Channel Through Cement Slurry	causes	0.7	Gas Migration
High Water Loss In Cement Slurry	caused by	0.7	Poor Cement Design
High Water Loss In Cement Slurry	causes	0.7	Cement Volume Reduction
High Water Loss In Cement Slurry	causes	0.7	Erosion Of Weak Formation
High Water Loss In Cement Slurry	causes	0.7	Too Slow Cement Hydration
High Water Loss In Cement Slurry	causes	0.7	Poor Cement Bond
High Water Loss In Cement Slurry	causes	0.7	Poor Cement Quality
Wellbore Temperature Fluctuation	caused by	0.7	Drilling Well
Wellbore Temperature Fluctuation	caused by	0.7	Injecting Steam
Wellbore Temperature Fluctuation	caused by	0.7	Producing Hydrocarbons
Wellbore Temperature Fluctuation	causes	0.7	Cyclic Casing Expansion/Contraction
Cyclic Casing Expansion/Contraction	causes	0.7	Poor Cement Bond
Cyclic Casing Expansion/Contraction	causes	0.7	Cyclic Cement Fatigue
Cyclic Casing Expansion/Contraction	causes	0.7	Microannulus
Cyclic Cement Fatigue	causes	0.7	Fractures In Cement Sheath

B. All Relevant Symptoms/Observations of each Case

Table 29: Observed symptoms from Case 2.

Sand Zone In Open Hole	Data agent
Small Fire Ignited On Rig Floor	Manual input
Bleed Off Annular Pressure	Manual input
Decrease In Annulus Fluid Level	Manual input
Miscommunication	Post incident
Insufficient Risk Analysis	Post incident

Table 30: Observed symptoms from Case 3.

Sudden Pump Pressure Drop	Data agent
Temporary Lost Return During Cementing	Manual input
Bubbling Mud In BOP Stack	Manual input
Pressure Drop During Bumping Of Cmt Plug	Manual input
Early Cement Return	Manual input
Maintaining Annular Liquid Level	Manual input
Too Short WOC Time	Manual input
High Well Inclination	Static info

Table 31: Observed symptoms from Case 4.

Increasing Annular Pressure	Manual input
Flow Indication Through Noise Log	Manual input
Flow Indication Through Temperature Log	Manual input
Early Cement Return	Manual input
Temporary Lost Return During Cementing	Manual input
Drilling Through Shallow Gas Sand	Manual input
Unable To Reciprocate	Static info
High Well Inclination	Static info
Previous Blowout In Neighbor Well	Static info

Table 32: Observed symptoms from Case 5.

Abnormal Pressure Decline During Injection	Manual input
Poor Seabed Visibility	Manual input
Seabed Erosion Pit	Manual input
Hydro Carbon Emissions To Sea Surface	Manual input
Shallow Gas Bearing Formation	Static info
Re-Injecting Cuttings In Same Fm	Static info
Inadequate Well Design	Post incident
Warning Signs Not Taken Serious	Post incident
Unclear Responsibility	Post incident
Underestimating Situation	Post incident
Inadequate Well Design	Post incident

C. Case Specific Concepts and Relations

Table 33: All possible relations from the symptoms from Case 1.

Concept 1	Relation	Strength	Concept 2
Previous Blowout In Neighbor Well	indicates	0.7	Shallow Gas Bearing Formation
Shallow Gas Bearing Formation	indicates	0.7	Drilling Through Shallow Sand
Drilling Through Shallow Sand	causes	0.7	Low Degree Of Compaction
Low Degree Of Compaction	causes	0.7	Low Surface Fracture Gradient
Low Surface Fracture Gradient	causes	0.7	Naturally Fractured Formation
Low Surface Fracture Gradient	causes	0.7	Induced Fracture
Lost Circulation	caused by	0.7	Naturally Fractured Formation
Lost Circulation	caused by	0.7	Induced Fracture
Shutting In Diverter	causes	0.7	Increasing Formation Pressure
Shutting In Diverter	causes	0.7	Increasing Upper Annular Pressure
Shutting In Diverter	caused by	0.7	Uncontrolled Flow In Cemented Annulus
Induced Fracture	caused by	0.7	Increasing Formation Pressure
Induced Fracture	caused by	0.7	Low Surface Fracture Gradient
Induced Fracture	caused by	0.7	Wrong Fracture Pressure Assumption
Induced Fracture	causes	0.7	Vertical Fracture To Surface
Induced Fracture	causes	0.7	Lost Circulation
Missing LOT	causes	0.7	Wrong Fracture Pressure Assumption
Increasing Annular Pressure	caused by	0.7	Gas Migration
Flow From Conductor Casing	caused by	0.7	Gas Migration
Poor Pre-Event Planning	causes	0.7	Poor Cement Quality
Poor Pre-Event Planning	causes	0.7	Inadequate Knowledge
Poor Pre-Event Planning	causes	0.7	Poor Procedure/Documentation
Gas Migration	caused by	0.7	Poor Cement Quality
Gas Migration	causes	0.7	Increasing Annular Pressure
Gas Migration	causes	0.7	Flow From Conductor Casing
Gas Migration	causes	0.7	Uncontrolled Flow In Cemented Annulus
Uncontrolled Flow In Cemented Annulus	causes	0.7	Blowout
Uncontrolled Flow In Cemented Annulus	causes	0.7	Shutting in Diverter
Uncontrolled Flow In Cemented Annulus	caused by	0.7	Gas Migration
Uncertainty About Equipment Limitation	caused by	0.7	Inadequate Knowledge
Uncertainty About Equipment Limitation	caused by	0.7	Poor Procedure/Documentation
Uncertainty About Equipment Limitation	causes	0.7	Increasing Formation Pressure
Uncertainty About Equipment Limitation	causes	0.7	Increasing Upper Annular Pressure
Uncertainty About Equipment Limitation	causes	0.7	Leak Through Diverter
Leak Through Diverter	causes	0.7	Detected Gas On Rig

Leak Through Diverter	causes	0.7	Blowout
Leak Through Diverter	caused by	0.7	Increasing Upper Annular Pressure
Leak Through Diverter	caused by	0.7	Uncertainty About Equipment Limitation
Leak Through Diverter	caused by	0.7	Cyclic Diverter Fatigue
Rocking Motions Of Rig	causes	0.7	Cyclic Diverter Fatigue

Table 34: All possible relations from Case 2.

Concept 1	**Relation**	**Strength**	**Concept 2**
Small Fire Ignition	caused by	0.7	Detected Gas On Rig
Detected Gas On Rig	caused by	0.7	Leak Through Annular Bleed Valve
Leak Through Annular Bleed Valve	caused by	0.7	Uncontrolled Flow In Cemented Annulus
Bleeding Off Annular Pressure	caused by	0.7	Increasing Annular Pressure
Bleeding Off Annular Pressure	causes	0.7	Decrease In Annulus Fluid Level
Decrease In Annulus Fluid Level	causes	0.7	Hydrostatic Pressure Loss In Cement Slurry
Hydrostatic Pressure Loss In Cement Slurry	causes	0.7	Gas Migration
Hydrostatic Pressure Loss In Cement Slurry	caused by	0.7	Missing Shallow Gas Additives In Cement Slurry
Missing Shallow Gas Additives In Cement Slurry	caused by	0.7	Miscommunication
Missing Shallow Gas Additives In Cement Slurry	caused by	0.7	Insufficient Risk Analysis
Sand Indication Through W.L.	causes	0.7	Drilling Through Shallow Gas Sand
Sand Indication Through W.L.	causes	0.7	Low Degree Of Compaction
Gas Migration	caused by	0.7	Hydrostatic Pressure Loss In Cement Slurry
Gas Migration	caused by	0.7	Drilling Through Shallow Gas Sand
Gas Migration	causes	0.7	Uncontrolled Flow In Cemented Annulus
Gas Migration	causes	0.7	Increasing Annular Pressure
Low Surface Fracture Gradient	caused by	0.7	Low Degree Of Compaction
Low Surface Fracture Gradient	causes	0.7	Induced Fracture
Low Surface Fracture Gradient	causes	0.7	Naturally Fractured Formation
Low Degree Of Compaction	causes	0.7	Reactive Formation
Lost Circulation	caused by	0.7	Induced Fracture
Lost Circulation	caused by	0.7	Naturally Fractured Formation
Vertical Fracture To Surface	caused by	0.7	Induced Fracture
Vertical Fracture To Surface	caused by	0.7	Naturally Fractured Formation

Table 35: All possible relations from Case 3.

Concept 1	Relation	Strength	Concept 2
Sudden Pump Pressure Drop	caused by	0,1	Pump Failure
Sudden Pump Pressure Drop	caused by	0.7	Hole In Circulation System
Sudden Pump Pressure Drop	caused by	0.7	Lost Circulation
Sudden Pump Pressure Drop	caused by	0.7	Temporary Lost Return
Temporary Lost Return	causes	0.7	Sudden Pump Pressure Drop
Temporary Lost Return	causes	0.7	Cement Escape To Formation
Temporary Lost Return	caused by	0.7	Naturally Fractured Formation
Temporary Lost Return	caused by	0.7	Induced Fracture
Cement Escape To Formation	causes	0.7	High Casing Corrosion
Cement Escape To Formation	causes	0.7	Poor Cement Quality
Maintaining Annular Liquid Level	caused by	0.7	Lost Circulation
Too Short WOC Time	causes	0.7	Low Cement Compressive Strength
Low Cement Compressive Strength	causes	0.7	Fractures In Cement Sheet
Bubbling Mud In BOP Stack	caused by	0.7	Gas Migration
Gas Migration	caused by	0.7	Fractures In Cement Sheet
Gas Migration	caused by	0.7	Poor Cement Bond
Gas Migration	caused by	0.7	Drilling Through Shallow Gas Sand
Gas Migration	caused by	0.7	Cement Channels Through Mud
Gas Migration	caused by	0.7	Ruptured External Casing Packer
Gas Migration	causes	0.7	Increasing Annular Pressure
Gas Migration	causes	0.7	Uncontrolled Flow In Cemented Annulus
Gas Migration	causes	0.7	Bubbling Mud In BOP Stack
High Well Inclination	causes	0.7	Casing In BUR
High Well Inclination	causes	0.7	Poor Centralized Casing
Poor Centralized Casing	causes	0.7	Non-Uniform Cement Column
Poor Centralized Casing	causes	0.7	Lower Ann. Flow In Activated Area
Non-Uniform Cement Column	causes	0.7	Poor Cement Quality
Lower Ann. Flow In Activated Area	causes	0.7	High Average Slurry Velocity
High Average Slurry Velocity	causes	0.7	High Annular Displacement Velocity
High Annular Displacement Velocity	causes	0.7	Higher Annular Dispersion
Early Cement Return	caused by	0.7	Higher Annular Dispersion
Higher Annular Dispersion	caused by	0.7	High Annular Displacement Velocity
Higher Annular Dispersion	causes	0.7	Early Cement Return
Higher Annular Dispersion	causes	0.7	Mud Contaminated Cement
Higher Annular Dispersion	causes	0.7	Poor Cement Bond
Mud Contaminated Cement	causes	0.7	Cement Channels Through Mud
Poor Cement Quality	caused by	0.7	Non-Uniform Cement Column
Poor Cement Quality	caused by	0.7	Mud Contaminated Cement
Poor Cement Quality	caused by	0.7	Cement Escape To Formation

Poor Cement Quality	causes	0.7	Poor Cement Bond
Poor Cement Quality	causes	0.7	Fractures In Cement Sheet
Fractures In Cement Sheet	causes	0.7	Undetected Leak Through Annulus
Fractures In Cement Sheet	causes	0.7	Gas Migration
Blowout	caused by	0.7	Uncontrolled Flow In Cemented Annulus
Blowout	caused by	0.7	Undetected Leak Through Annulus
Blowout	caused by	0.7	Vertical Fracture To Surface
Pressure Drop During Bumping Of Cement Plug	caused by	0.7	Ruptured External Casing Packer
Ruptured External Casing Packer	caused by	0.7	High Casing Corrosion
Ruptured External Casing Packer	causes	0.7	Gas Migration

Table 36: All possible relations from symptoms from Case 4.

Concept 1	Relation	Strength	Concept 2
Increasing Annular Pressure	caused by	0.7	Gas Migration
Early Cement Return	caused by	0.7	Axial Dispersion Of Cement Slurry
High Well Inclination	causes	0.7	Unable To Reciprocate
High Well Inclination	causes	0.7	Poor Centralized Casing
Flow Indication Through Noise Log	caused by	0.7	Uncontrolled Flow In Cemented Annulus
Flow Indication Through Temperature Log	caused by	0.7	Uncontrolled Flow In Cemented Annulus
Poor Centralized Casing	causes	0.7	Lower Ann. Flow In Activated Area
Poor Centralized Casing	causes	0.7	Non-Uniform Cement Column
Lower Ann. Flow In Activated Area	causes	0.7	High Average Slurry Velocity
High Average Slurry Velocity	causes	0.7	Higher Annular Displacement Velocity
Higher Annular Displacement Velocity	causes	0.7	Higher Annular Dispersion
Unable To Reciprocate	causes	0.7	Higher Annular Dispersion
Higher Annular Dispersion	causes	0.7	Mud Contaminated Cement
Higher Annular Dispersion	causes	0.7	Poor Cement Bond
Higher Annular Dispersion	causes	0.7	Early Cement Return
Mud Contaminated Cement	causes	0.7	Cement Channels Through Mud
Mud Contaminated Cement	causes	0.7	Poor Cement Quality
Poor Cement Quality	causes	0.7	Fractures In Cement Sheet
Poor Cement Quality	causes	0.7	Gas Migration
Poor Cement Quality	causes	0.7	Poor Cement Bond
Poor Cement Quality	caused by	0.7	Cement Escape To Formation
Poor Cement Quality	caused by	0.7	Non-Uniform Cement Column
Poor Cement Quality	caused by	0.7	Mud Contaminated Cement
Poor Cement Quality	caused by	0.7	Low Surface Fracture Gradient

Fractures In Cement Sheet	causes	0.7	Undetected Leak Through Annulus
Fractures In Cement Sheet	causes	0.7	Gas Migration
Gas Migration	causes	0.7	Uncontrolled Flow In Cemented Annulus
Gas Migration	causes	0.7	Increasing Annular Pressure
Gas Migration	caused by	0.7	Poor Cement Bond
Gas Migration	caused by	0.7	Fractures In Cement Sheet
Gas Migration	caused by	0.7	Poor Cement Quality
Gas Migration	caused by	0.7	Cement Channels Through Mud
Blowout	caused by	0.7	Uncontrolled Flow In Cemented Annulus
Blowout	caused by	0.7	Undetected Leak Through Annulus
Blowout	caused by	0.7	Vertical Fracture To Surface
Previous Blowout In Neighbor Well	causes	0.7	Shallow Gas Bearing Formation
Shallow Gas Bearing Formation	causes	0.7	Low Degree Of Compaction
Shallow Gas Bearing Formation	causes	0.7	Drilling Through Shallow Gas Sand
Drilling Through Shallow Gas Sand	caused by	0.7	Shallow Gas Bearing Formation
Drilling Through Shallow Gas Sand	causes	0.7	Low Degree Of Compaction
Low Degree Of Compaction	causes	0.7	Induced Fracture
Low Degree Of Compaction	causes	0.7	Naturally Fractured Formation
Temporary Lost Return	causes	0.7	Cement Escape To Formation
Temporary Lost Return	caused by	0.7	Induced Fracture
Temporary Lost Return	caused by	0.7	Naturally Fractured Formation
Lost Circulation	caused by	0.7	Induced Fracture
Lost Circulation	caused by	0.7	Naturally Fractured Formation
Vertical Fracture To Surface	caused by	0.7	Induced Fracture
Vertical Fracture To Surface	caused by	0.7	Naturally Fractured Formation
Vertical Fracture To Surface	causes	0.7	Blowout

Table 37: All possible relations from Case 5.

Concept	**Relation**	**Strength**	**Concept**
Abnormal Injection Pressure Decline	caused by	0.7	Lost Circulation
Sudden Pump Pressure Drop	caused by	0.7	Lost Circulation
Sudden Pump Pressure Drop	caused by	0.7	Drill String Wash Out
Sudden Pump Pressure Drop	caused by	0.7	Hole In Circulation System
Sudden Pump Pressure Drop	caused by	0.7	Pump Failure
Shallow Gas Bearing Formation	causes	0.7	Gas Migration
Shallow Gas Bearing Formation	causes	0.7	Low Degree Of Compaction
Low Degree Of Compaction	causes	0.7	Low Surface Fracture Gradient
Low Surface Fracture Gradient	causes	0.7	Induced Fracture
Low Surface Fracture Gradient	causes	0.7	Naturally Fractured Fm
Induced Fracture	causes	0.7	Lost Circulation
Induced Fracture	causes	0.7	Vertical Fracture To Surface

Naturally Fractured Fm	causes	0.7	Lost Circulation
Naturally Fractured Fm	causes	0.7	Vertical Fracture To Surface
Vertical Fracture To Surface	causes	0.7	Blowout
Poor Seabed Visibility	caused by	0.7	Blowout
Seabed Erosion Pit	caused by	0.7	Blowout
Emissions To Sea Surface	caused by	0.7	Blowout
Re-Injecting Cuttings	causes	0.7	Pressure Increase In Zone
Re-Injecting Cuttings	causes	0.7	Wellbore Temperature Fluctuation
Re-Injecting Cuttings	causes	0.7	Wellbore Pressure Fluctuation
Pressure Increase In Zone	causes occasionally	0,1	Vertical Fracture To Surface
Mechanical Stress On Hard Cement	caused by	0.7	Wellbore Temperature Fluctuation
Mechanical Stress On Hard Cement	caused by	0.7	Wellbore Pressure Fluctuation
Mechanical Stress On Hard Cement	causes	0.7	Fractures In Cement Sheet
Fractures In Cement Sheet	caused by	0.7	Mechanical Stress On Hard Cement
Fractures In Cement Sheet	caused by		Poor Cement Quality
Fractures In Cement Sheet	causes		Gas Migration
Fractures In Cement Sheet	causes		Undetected Leak Through Annulus
Unclear Responsibility	causes	0.7	Inattentive To Warning Signs
Underestimating Situation	causes	0.7	Inattentive To Warning Signs
Underestimating Situation	causes	0.7	Warning Signs Not Taken Serious
Warning Signs Not Taken Serious	causes	0.7	Inattentive To Warning Signs
Warning Signs Not Taken Serious	causes	0.7	Failure To Follow Procedure
Failure To Follow Procedure	causes	0.7	Undetected Leak Through Annulus
Inattentive To Warning Signs	causes	0.7	Uncontrolled Flow In Cemented Annulus
Inadequate Well Design	causes	0.7	Poor Cement Design
Inadequate Well Design	causes	0.7	Poor Centralized Casing
Poor Centralized Casing	causes	0.7	Non-Uniform Cement Column
Poor Centralized Casing	causes	0.7	Lower Ann. Flow In Activated Area
Non-Uniform Cement Column	causes	0.7	Poor Cement Quality
Lower Ann. Flow In Activated Area	causes	0.7	High Average Slurry Velocity
High Average Slurry Velocity	causes	0.7	Higher Annular Displacement Velocity
Higher Annular Displacement Velocity	causes	0.7	Higher Annular Dispersion
Higher Annular Dispersion	causes	0.7	Mud Contaminated Cement
Higher Annular Dispersion	causes	0.7	Poor Cement Bond
Mud Contaminated Cement	causes	0.7	Poor Cement Quality
Mud Contaminated Cement	causes	0.7	Cement Channels Through Mud

Gas Migration	caused by	0.7	Poor Cement Quality
Gas Migration	caused by	0.7	Poor Cement Bond
Gas Migration	caused by	0.7	Cement Channels Through Mud
Gas Migration	caused by	0.7	Fractures In Cement Sheet
Gas Migration	caused by	0,1	Shallow Gas Bearing Fm
Gas Migration	causes	0.7	Uncontrolled Flow In Cemented Annulus
Blowout	caused by	0.7	Uncontrolled Flow In Cemented Annulus
Blowout	caused by	0.7	Undetected Leak Through Annulus
Blowout	caused by	0.7	Vertical Fracture To Surface

D. Case Specific Failure Calculations

Table 38: Observations, path strength, explanation strength and resulting failure probability from Case 1.

Observations	Involved relation strengths	Path strength	Failure	Explanation Strength	Probability [%]
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7	0,12	Lost Circulation	1,58	31,2
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Shutting In Diverter	0.7 0.7 0.7	0,34			
Missing LOT	0.7 0.7 0.7	0,34			
Increasing Annular Pressure	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Flow From Conductor Casing	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Poor Pre-Event Planning	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Poor Pre-Event Planning	0.7 0.7 0.7 0.7 0.7	0,17			
Poor Pre-Event Planning	0.7 0.7 0.7 0.7 0.7	0,17			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08	Blowout	3,47	68,8
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Shutting In Diverter	0.7 0.7 0.7 0.7	0,24			
Shutting In Diverter	0.7 0.7	0,49			
Shutting In Diverter	0.7 0.7 0.7	0,34			
Missing LOT	0.7 0.7 0.7 0.7	0,24			
Increasing Annular Pressure	0.7 0.7 0.7	0,34			
Flow From Conductor Casing	0.7 0.7 0.7	0,34			
Poor Pre-Event Planning	0.7 0.7 0.7 0.7	0,24			
Poor Pre-Event Planning	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Poor Pre-Event Planning	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Detected Gas On Rig	0.7 0.7	0,49			
Rocking Motions Of Rig	0.7 0.7 0.7	0,34			
Total		5,05			100,0

Table 39: Observations, path strength, explanation strength and resulting failure probability from Case 2.

Observations	Involved relation strengths	Path strength	Failure	Explanation Strength	Probability [%]
Small Fire Ignited On Rig Floor	0.7 0.7 0.7 0.7	0,24	Blowout	1,80	78,9
Bleeding Off Annular Pressure	0.7 0.7 0.7 0.7	0,24			
Bleeding Off Annular Pressure	0.7 0.7 0.7 0.7 0.7	0,17			
Decrease In Annulus Fluid Level	0.7 0.7 0.7 0.7	0,24			
Sand Zone In Open Hole	0.7 0.7 0.7 0.7	0,24			
Sand Zone In Open Hole	0.7 0.7 0.7 0.7 0.7	0,17			
Sand Zone In Open Hole	0.7 0.7 0.7 0.7 0.7	0,17			
Miscommunication	0.7 0.7 0.7 0.7 0.7	0,17			
Insufficient Risk Analysis	0.7 0.7 0.7 0.7 0.7	0,17			
Sand Zone In Open Hole	0.7 0.7 0.7 0.7	0,24	Lost Circulation	0,48	21,1
Sand Zone In Open Hole	0.7 0.7 0.7 0.7	0,24			
Total		2,28			100,0

Table 40: Observations, path strength, explanation strength and resulting failure probability from Case 3.

Observations	Involved relation strengths	Path strength	Failure	Explanation Strength	Probability [%]
Sudden Pump Pressure Drop	0.7 0.7 0.7	0,34	Blowout	3,48	62,4
Temporary Lost Return	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Temporary Lost Return	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Temporary Lost Return	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Temporary Lost Return	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Temporary Lost Return	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Temporary Lost Return	0.7 0.7 0.7 0.7 0.7	0,17			
Temporary Lost Return	0.7 0.7 0.7 0.7	0,24			
Too Short WOC Time	0.7 0.7 0.7 0.7	0,24			
Too Short WOC Time	0.7 0.7 0.7 0.7 0.7	0,17			
Bubbling Mud In BOP Stack	0.7 0.7 0.7	0,34			
Pressure Drop During Bumping Of Cmt Plug	0.7 0.7 0.7 0.7	0,24			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,03			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,02			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,02			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,03			

High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,04			
Early Cement Return	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Early Cement Return	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Early Cement Return	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Early Cement Return	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Early Cement Return	0.7 0.7 0.7 0.7 0.7	0,17			
Sudden Pump Pressure Drop	0.7	0.70	Lost Circulation	1,40	25,1
Maintaining Annular Liquid Level	0.7	0.70			
Sudden Pump Pressure Drop	0.7	0.70	Pump Failure	0.7	12,5
Total		5,58			100,0

Table 41: Observations, path strength, explanation strength and resulting failure probability from Case 4.

Observations	Involved relation strengths	Path strength	Failure	Explanation Strength	Probability [%]
Increasing Annular Pressure	0.7 0.7 0.7	0,34	Blowout	7,12	77,8
Flow Indication Through Noise Log	0.7 0.7	0,49			
Flow Indication Through Temperature Log	0.7 0.7	0,49			
Early Cement Return	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Early Cement Return	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Early Cement Return	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Early Cement Return	0.7 0.7 0.7 0.7 0.7	0,17			
Early Cement Return	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Early Cement Return	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Unable To Reciprocate	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Unable To Reciprocate	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Unable To Reciprocate	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Unable To Reciprocate	0.7 0.7 0.7 0.7 0.7	0,17			
Unable To Reciprocate	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Unable To Reciprocate	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,06			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,06			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,03			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,03			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,02			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,04			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,02			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,03			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			

High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
High Well Inclination	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,06			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,06			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,06			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,04			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,04			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,06			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7	0,17			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Drilling Through Shallow Gas Sand	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Drilling Through Shallow Gas Sand	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Drilling Through Shallow Gas Sand	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Drilling Through Shallow Gas Sand	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Drilling Through Shallow Gas Sand	0.7 0.7 0.7 0.7 0.7	0,17			
Drilling Through Shallow Gas Sand	0.7 0.7 0.7 0.7 0.7	0,17			
Drilling Through Shallow Gas Sand	0.7 0.7 0.7	0,34			
Temporary Lost Return	0.7 0.7 0.7	0,34			
Temporary Lost Return	0.7 0.7 0.7	0,34			
Temporary Lost Return	0.7 0.7 0.7 0.7 0.7	0,17			
Temporary Lost Return	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Temporary Lost Return	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Temporary Lost Return	0.7 0.7 0.7 0.7 0.7	0,17			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7	0,17	Lost Circulation	2,03	22,2
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7	0,17			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Previous Blowout In Neighbor Well	0.7 0.7 0.7 0.7 0.7 0.7	0,12			

Drilling Through Shallow Gas Sand	0.7 0.7 0.7 0.7	0,24			
Drilling Through Shallow Gas Sand	0.7 0.7 0.7 0.7	0,24			
Temporary Lost Return	0.7 0.7	0,49			
Temporary Lost Return	0.7 0.7	0,49			
Total		9,15			100,0

Table 42: Observations, path strength, explanation strength and resulting failure probability from Case 5.

Observations	Involved relation strengths	Path strength	Failure	Explanation Strength	Probability [%]
Abnormal Decline In Injection Pressure	0.7	0.70	Lost Circulation	1,18	13,7
Shallow Gas Bearing Formation	0.7 0.7 0.7 0.7	0,24			
Shallow Gas Bearing Formation	0.7 0.7 0.7 0.7	0,24			
Abnormal Decline In Injection Pressure	0.7	0.70	Pump Failure	0.70	8,1
Abnormal Decline In Injection Pressure	0.7 0.7 0.7	0,34	Blowout	6,73	78,2
Shallow Gas Bearing Formation	0.7 0.7 0.7 0.7 0.7	0,17			
Shallow Gas Bearing Formation	0.7 0.7 0.7 0.7 0.7	0,17			
Shallow Gas Bearing Formation	0.7 0.7 0.7	0,34			
Poor Seabed Visibility	0.7	0.70			
Seabed Erosion Pit	0.7	0.70			
Hydro Carbon Emissions To Sea Surface	0.7	0.70			
Re-Injecting Cuttings In Same Formation	0.7 0.1 0.7	0,05			
Re-Injecting Cuttings In Same Formation	0.7 0.7 0.7 0.7 0.7	0,17			
Re-Injecting Cuttings In Same Formation	0.7 0.7 0.7 0.7 0.7	0,17			
Re-Injecting Cuttings In Same Formation	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Re-Injecting Cuttings In Same Formation	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Unclear Responsibility	0.7 0.7 0.7	0,34			
Underestimating Situation	0.7 0.7 0.7	0,34			
Underestimating Situation	0.7 0.7 0.7 0.7	0,24			
Underestimating Situation	0.7 0.7 0.7 0.7	0,24			
Warning Signs Not Taken Serious	0.7 0.7 0.7	0,34			
Warning Signs Not Taken Serious	0.7 0.7 0.7	0,34			
Inadequate Well Design	0.7 0.7 0.7 0.7 0.7	0,17			
Inadequate Well Design	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Inadequate Well Design	0.7 0.7 0.7 0.7 0.7	0,17			
Inadequate Well Design	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Inadequate Well Design	0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Inadequate Well Design	0.7 0.7 0.7 0.7 0.7 0.7	0,08			

Inadequate Well Design	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,12			
Inadequate Well Design	0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,08			
Inadequate Well Design	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,03			
Inadequate Well Design	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,02			
Inadequate Well Design	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,03			
Inadequate Well Design	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,02			
Inadequate Well Design	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,04			
Inadequate Well Design	0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7 0.7	0,03			
Total		8,61			100,0

E. Case Specific Target Error Calculations

Table 43: Target error calculations for Case 1.

Observations	Involved relation strengths	Path strength	Target error	Explanation Strength	Probability [%]
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*.7*0.7	0,12	Vertical Fracture To Surface	1,26	20,5
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*.7*0.7	0,12			
Missing LOT	0.7*0.7*0.7	0,34			
Shutting In Diverter	0.7*0.7*0.7	0,34			
Poor Pre-Event Planning	0.7*0.7*0.7*0.7*0.7	0,17			
Poor Pre-Event Planning	0.7*0.7*0.7*0.7*0.7	0,17			
Shutting In Diverter	0.7	0.70	Uncontrolled Flow In Cemented Annulus	2,02	33,0
Increasing Annular Pressure Short After Cementing	0.7*0.7	0,49			
Flow From Conductor Casing	0.7*0.7	0,49			
Poor Pre-Event Planning	0.7*0.7*0.7	0,34			
Shutting In Diverter	0.7*0.7	0,49	Leak Through Diverter	2,85	46,5
Poor Pre-Event Planning	0.7*0.7*0.7*0.7	0,24			
Poor Pre-Event Planning	0.7*0.7*0.7	0,34			
Poor Pre-Event Planning	0.7*0.7*0.7*0.7	0,24			
Poor Pre-Event Planning	0.7*0.7*0.7	0,34			
Detected Gas On Rig	0.7	0.70			
Rocking Motions Of Rig	0.7*0.7	0,49			
Total		6,13			100,0

Table 44: Target error calculations for Case 2.

Observations	Involved relation strengths	Path strength	Target error	Explanation Strength	Probability [%]
Small Fire Ignited On Rig Floor	0.7*0.7*0.7	0,34	Uncontrolled Flow In Cemented Annulus	2,09	81,3
Bleeding Off Annular Pressure	0.7*0.7*0.7	0,34			
Bleeding Off Annular Pressure	0.7*0.7*0.7*0.7	0,24			
Decrease In Annulus Fluid Level	0.7*0.7*0.7	0,34			
Sand Zone In Open Hole	0.7*0.7*0.7	0,34			
Miscommunication	0.7*0.7*0.7*0.7	0,24			
Insufficient Risk Analysis	0.7*0.7*0.7*0.7	0,24			
Sand Zone In Open Hole	0.7*0.7*0.7*0.7	0,24	Vertical Fracture To Surface	0,48	18,7
Sand Zone In Open Hole	0.7*0.7*0.7*0.7	0,24			
Total		2,57			100,0

Table 45: Target errors calculations for Case 3.

Observations	Involved relation strengths	Path strength	Target error	Explanation Strength	Probability [%]
Sudden Pump Pressure Drop	0.7*0.7	0,49	Vertical Fracture To Surface	1,24	26,1
Temporary Lost Return During Cementing	0.7*0.7*0.7*0.7	0,24			
Temporary Lost Return During Cementing	0.7*0.7*0.7	0,34			
High Well Inclination	0.7*0.7*0.7*0.7*0.7	0,17			
Too Short WOC Time	0.7*0.7*0.7	0,34	Undetected Leak Through Annulus	0,96	20,2
Temporary Lost Return During Cementing	0.7*0.7*0.7*0.7	0,24			
High Well Inclination	0.7*0.7*0.7*0.7*0.7	0,17			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
Early Cement Return	0.7*0.7*0.7*0.7*0.7	0,17			
Temporary Lost Return During Cementing	0.7*0.7*0.7*0.7*0.7*0.7	0,12	Uncontrolled Flow In Cemented Annulus	2,55	53,7
Temporary Lost Return During Cementing	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
Too Short WOC Time	0.7*0.7*0.7*0.7	0,24			
Bubbling Mud In BOP Stack	0.7*0.7	0,49			
Pressure Drop During Bumping Of Cmt Plug	0.7*0.7*0.7	0,34			
High Well Inclination	0.7*0.7*0.7*0.7*0.7	0,17			
High Well Inclination	0.7*0.7*0.7*0.7*0.7	0,17			
High Well Inclination	0.7*0.7*0.7*0.7*0.7	0,17			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,03			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,03			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
Early Cement Return	0.7*0.7*0.7*0.7	0,24			
Early Cement Return	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
Early Cement Return	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
Early Cement Return	0.7*0.7*0.7*0.7*0.7	0,17			
Total		4,75			100,0

Table 46: Target error calculations for Case 4.

Observations	Involved relation strengths	Path strength	Target error	Expl. Strength	Probability [%]
Flow Indication Through Temperature Log	0.7	0.70	Uncontrolled Flow In Cemented Annulus	6,37	70,1

Flow Indication Through Noise Log	0.7	0.70			
Increasing Annular Pressure Short After Cementing	0.7*0.7	0,49			
Early Cement Return	0.7*0.7*0.7*0.7*0.7	0,17			
Early Cement Return	0.7*0.7*0.7*0.7	0,24			
Early Cement Return	0.7*0.7*0.7*0.7*0.7	0,17			
Early Cement Return	0.7*0.7*0.7*0.7*0.7	0,12			
Unable To Reciprocate	0.7*0.7*0.7*0.7*0.7	0,17			
Unable To Reciprocate	0.7*0.7*0.7*0.7	0,24			
Unable To Reciprocate	0.7*0.7*0.7*0.7*0.7	0,17			
Unable To Reciprocate	0.7*0.7*0.7*0.7*0.7	0,12			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
High Well Inclination	0.7*0.7*0.7*0.7*0.7	0,17			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,08			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,08			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,06			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
High Well Inclination	0.7*0.7*0.7*0.7*0.7	0,17			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,03			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,03			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,08			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,06			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,06			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,06			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7	0,24			
Drilling Through Shallow Gas Sand	0.7*0.7	0,49			
Drilling Through Shallow Gas Sand	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
Drilling Through Shallow Gas Sand	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,08			
Drilling Through Shallow Gas Sand	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,08			
Temporary Lost Return During Cementing	0.7*0.7*0.7*0.7	0,24			
Temporary Lost Return During Cementing	0.7*0.7*0.7*0.7*0.7	0,17			
Temporary Lost Return During Cementing	0.7*0.7*0.7*0.7*0.7	0,17			
Early Cement Return	0.7*0.7*0.7*0.7*0.7	0,17	Undetected Leak Through Annulus	1,16	12,8

Unable To Reciprocate	0.7*0.7*0.7*0.7*0.7	0,17			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
High Well Inclination	0.7*0.7*0.7*0.7*0.7	0,17			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,08			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,06			
Drilling Through Shallow Gas Sand	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
Temporary Lost Return During Cementing	0.7*0.7*0.7*0.7	0,24			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7	0,17	Vertical Fracture To Surface	1,55	17,1
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7	0,17			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
Temporary Lost Return During Cementing	0.7*0.7	0,49			
Temporary Lost Return During Cementing	0.7*0.7	0,49			
Total		9,08			100,0

Table 47: Target error calculations for Case 5.

Observations	Involved relation strengths	Path str.	Target error	Expl. Strength	Probability [%]
Abnormal Decline In Injection Pressure	0.7*0.7	0,49	Vertical Fracture To Surface	1,04	15,5
Shallow Gas Bearing Fm	0.7*0.7*0.7*0.7	0,24			
Shallow Gas Bearing Fm	0.7*0.7*0.7*0.7	0,24			
Re-Injecting Cuttings In Same Formation	0.7*0.1	0,07			
Re-Injecting Cuttings In Same Formation	0.7*0.7*0.7*0.7	0,24	Undetected Leak Through Annulus	1,98	29,5
Re-Injecting Cuttings In Same Formation	0.7*0.7*0.7*0.7	0,24			
Warning Signs Not Taken Serious	0.7*0.7	0,49			
Underestimating Situation	0.7*0.7*0.7	0,34			
Inadequate Well Design	0.7*0.7*0.7	0,34			
Inadequate Well Design	0.7*0.7*0.7*0.7	0,24			
Inadequate Well Design	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,08			
Unclear Responsibility	0.7*0.7	0,49	Uncontrolled Flow In Cemented Annulus	3,69	55,0
Underestimating Situation	0.7*0.7	0,49			
Underestimating Situation	0.7*0.7*0.7	0,34			
Warning Signs Not Taken Serious	0.7*0.7	0,49			

Shallow Gas Bearing Fm	0.7*0.7	0,49			
Re-Injecting Cuttings In Same Formation	0.7*0.7*0.7*0.7	0,24			
Re-Injecting Cuttings In Same Formation	0.7*0.7*0.7*0.7	0,24			
Re-Injecting Cuttings In Same Formation	0.7*0.7*0.7*0.7*0.7	0,17			
Re-Injecting Cuttings In Same Formation	0.7*0.7*0.7*0.7*0.7	0,17			
Inadequate Well Design	0.7*0.7*0.7*0.7	0,24			
Inadequate Well Design	0.7*0.7*0.7*0.7*0.7	0,17			
Inadequate Well Design	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
Inadequate Well Design	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,03			
Inadequate Well Design	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
Inadequate Well Design	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,06			
Total		6,71			100,0

F. Case Specific Error Calculations

Table 48: Error calculations for Case 1.

Observations	Involved relation strengths	Path strength	Error	Explanation Strength	Probability [%]
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7	0,17	Naturally Fractured Fm	0,17	3,4
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7	0,17	Induced Fracture	1,84	37,2
Missing LOT	0.7*0.7	0,49			
Shutting In Diverter	0.7	0.70			
Poor Pre-Event Planning	0.7*0.7*0.7*0.7	0,24			
Poor Pre-Event Planning	0.7*0.7*0.7*0.7	0,24			
Previous Blowout In Neighbor Well	0.7*0.7*0.7	0,34	Gas Migration	2,23	45,2
Increasing Annular Pressure Short After Cementing	0.7	0.70			
Flow From Conductor Casing	0.7	0.70			
Poor Pre-Event Planning	0.7*0.7	0,49			
Rocking Motions Of Rig	0.7	0.70	Cyclic Diverter Fatigue	0.70	14,2
Total		4,94			100,0

Table 49: Error calculations for Case 2.

Observations	Involved relation strengths	Path strength	Error	Explanation Strength	Probability [%]
Small Fire Ignited On Rig Floor	0.7*0.7	0,49	Leak Through Annular Bleed Valve	0,49	13,3
Bleeding Off Annular Pressure	0.7*0.7	0,49	Gas Migration	2,50	68,0
Bleeding Off Annular Pressure	0.7*0.7*0.7	0,34			
Decrease In Annulus Fluid Level	0.7*0.7	0,49			
Sand Zone In Open Hole	0.7*0.7	0,49			
Miscommunication	0.7*0.7*0.7	0,34			
Insufficient Risk Analysis	0.7*0.7*0.7	0,34			
Sand Zone In Open Hole	0.7*0.7*0.7	0,34	Induced Fracture	0,34	9,3
Sand Zone In Open Hole	0.7*0.7*0.7	0,34	Naturally Fractured Fm	0,34	9,3
Total		3,68			100,0

Table 50: Error calculations for Case 3.

Observations	Involved relation strengths	Path strength	Error	Explanation Strength	Probability [%]
Sudden Pump Pressure Drop	0.7	0.70	Hole In Circulation System	1,43	29,9
Temporary Lost Return During Cementing	0.7*0.7	0,49			
High Well Inclination	0.7*0.7*0.7*0.7	0,24			
Temporary Lost Return During Cementing	0.7*0.7*0.7*0.7*0.7	0,17	Gas Migration	3,35	70,1
Temporary Lost Return During Cementing	0.7*0.7*0.7*0.7*0.7	0,17			
Too Short WOC Time	0.7*0.7*0.7	0,34			
Bubbling Mud In BOP Stack	0.7	0.70			
Pressure Drop During Bumping Of Cmt Plug	0.7*0.7	0,49			
High Well Inclination	0.7*0.7*0.7*0.7*0.7	0,17			
High Well Inclination	0.7*0.7*0.7*0.7*0.7	0,17			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,06			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,08			
Early Cement Return	0.7*0.7*0.7*0.7*0.7	0,17			
Early Cement Return	0.7*0.7*0.7*0.7*0.7	0,17			
Early Cement Return	0.7*0.7*0.7*0.7	0,24			
Early Cement Return	0.7*0.7*0.7	0,34			
Total		4,78			100,0

Table 51: Error calculations for Case 4.

Observations	Involved relation strengths	Path strength	Error	Explanation Strength	Probability [%]
Increasing Annular Pressure Short After Cementing	0.7	0.70	Gas Migration	7,10	71,0
Early Cement Return	0.7*0.7*0.7*0.7	0,24			
Early Cement Return	0.7*0.7*0.7	0,34			
Early Cement Return	0.7*0.7*0.7*0.7	0,24			
Early Cement Return	0.7*0.7*0.7*0.7*0.7	0,17			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7	0,17			
High Well Inclination	0.7*0.7*0.7*0.7*0.7	0,24			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,12			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7	0,17			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,12			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,06			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,08			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,06			
High Well Inclination	0.7*0.7*0.7*0.7*0.7	0,24			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7	0,17			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
High Well Inclination	0.7*0.7*0.7*0.7*0.7*0.7	0,17			

Unable To Reciprocate	0.7*0.7*0.7*0.7*0.7	0,24			
Unable To Reciprocate	0.7*0.7*0.7*0.7	0,34			
Unable To Reciprocate	0.7*0.7*0.7*0.7*0.7	0,24			
Unable To Reciprocate	0.7*0.7*0.7*0.7*0.7	0,17			
Drilling Through Shallow Gas Sand	0.7	0.70			
Drilling Through Shallow Gas Sand	0.7*0.7*0.7*0.7*0.7	0,17			
Drilling Through Shallow Gas Sand	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
Drilling Through Shallow Gas Sand	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
Previous Blowout In Neighbor Well	0.7*0.7*0.7	0,34			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7	0,12			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,08			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,08			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,08			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,06			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,06			
Temporary Lost Return During Cementing	0.7*0.7*0.7	0,34			
Temporary Lost Return During Cementing	0.7*0.7*0.7*0.7	0,24			
Temporary Lost Return During Cementing	0.7*0.7*0.7*0.7	0,24			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7	0,24	Induced Fracture	1,45	14,5
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7	0,17			
Drilling Through Shallow Gas Sand	0.7*0.7*0.7	0,34			
Temporary Lost Return During Cementing	0.7	0.70			
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7	0,24	Naturally Fractured Fm	1,45	14,5
Previous Blowout In Neighbor Well	0.7*0.7*0.7*0.7*0.7	0,17			
Drilling Through Shallow Gas Sand	0.7*0.7*0.7	0,34			
Temporary Lost Return During Cementing	0.7	0.70			
Total		10,00			100,0

Table 52: Error calculations for Case 5.

Observations	Involved relation strengths	Path strength	Error	Expl. Strength	Probability [%]
Shallow Gas Bearing Formation	0.7*0.7*0.7	0,34	Induced Fracture	0,34	7,3
Shallow Gas Bearing Formation	0.7*0.7*0.7	0,34	Naturally Fractures Fm	0,34	7,3
Abnormal Decline In Injection Pressure	0.7	0.70	Hole In Circulation System	0.70	14,8
Shallow Gas Bearing Formation	0.7	0.70	Gas Migration	3,34	70.7
Re-Injecting Cuttings In Same Fm	0.7*0.7*0.7*0.7	0,24			
Re-Injecting Cuttings In Same Fm	0.7*0.7*0.7*0.7	0,24			
Re-Injecting Cuttings In Same Fm	0.7*0.7*0.7*0.7	0,24			
Re-Injecting Cuttings In Same Fm	0.7*0.7*0.7*0.7	0,24			
Inadequate Well Design	0.7*0.7*0.7*0.7	0,24			
Inadequate Well Design	0.7*0.7*0.7*0.7	0,24			
Inadequate Well Design	0.7*0.7*0.7	0,34			
Inadequate Well Design	0.7*0.7*0.7*0.7*0.7	0,17			
Inadequate Well Design	0.7*0.7*0.7*0.7*0.7	0,17			
Inadequate Well Design	0.7*0.7*0.7*0.7	0,24			
Inadequate Well Design	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
Inadequate Well Design	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,04			
Inadequate Well Design	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,06			
Inadequate Well Design	0.7*0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,06			
Inadequate Well Design	0.7*0.7*0.7*0.7*0.7*0.7*0.7	0,08			
Total		4,72			100,0