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Table of content

List of tables

List of formulas

List of figures

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Abstract

Lost circulation (downhole losses of drilling fluid) is defined by the absence or reduction of drilling fluid pumped through the drill string while drilling the wells, which filtrates the formation instead of flowing up to the surface. The Lost circulation is a costly and challenging problem for the industry, and an extensive amount of money is used to prevent and mitigate this. Lost circulation can occur at any formation drilled and any well sections where a pressure imbalance is present, and the formation breakdown pressure is less than the total hydrostatic pressure in the well.

There are different strategies and methods used in the Oil and Gas industry to prevent lost circulation. Lost Circulation Material (LCM) is used as a wellbore strengthening strategy to prevent and cure downhole losses. The LCM treatment is either a remedial or a preventative treatment and can be added continuously into the wellbore or be spotted as a concentrated LCM pill.

Environmental emission considerations are closely monitored and crucial if the Oil and Gas industry shall be up and running in the years to come. Lost circulation issues contribute to a higher environmental discharge.

This thesis aims to investigate the LCM methods used and their cost, the cost of lost circulation and environmental impact caused by lost circulation. This was studied by analyzing different final well reports from different operators. In addition, drilling professionals have been interviewed to get further insight and information. Where severe downhole losses had occurred, the wells were in-depth analyzed to find the cost of total drilling fluid lost, LCM used, environmental discharge, and NPT due to lost circulation.

The analysis' main findings indicated that graphite and $CaCO_3$ as an LCM were used, in combination or alone, in 74% of the wells where severe losses had occurred. Furthermore, the cost of NPT in wells with severe downhole losses was, in average, 50 times larger than the average LCM cost. The average cost of LCM used approximately equaled the cost of one hour of NPT. Finally, a standardized LCM testing, reporting, and decision flow chart is strongly recommended to easier draw suitable conclusions. This will give a good basis for further development.

1 Introduction

In this thesis, a selection of final well reports (FWR) from the Norwegian Continental Shelf (NCS) are analyzed with the focus on downhole losses of drilling fluid, lost circulation material (LCM) used, non-productive time (NPT) due to downhole losses and the cost regarding them. In addition, interviews with drilling professionals have been conducted to analyze and understand these downhole losses. It is investigated by studying final well reports and interviewing drilling professionals if some formations or drilled sections are accountable for losses and how losses are handled preventive and remedial in the respective formations and sections. Questions were raised regarding the cost of today´s solutions and whether they work. First different formation zones of interest will be described. Further information is given to give a foundation and background to understand this thesis objectives. The Objective is introduced in the following chapter. The most expensive consequences due to lost circulation are changes in casing program and drilling a sidetrack. However, in the evaluated reports there were no such incidents. Hence, these items are not discussed in this thesis.

1.1 Zone description

Several formation types exist on the NCS. and the formations of interest will be described based on downhole losses and lost circulation in the NCS. The formations discussed in this thesis are:

- Limestone
- Sandstone and shale formation
- Coal formation
- Karstified formation

1.1.1 Limestone formations

Limestone formations are formations of interest due to that they usually are naturally fractured. Unfortunately, this might lead to a high potential for downhole losses.

Limestone is a sedimentary rock with Calcium Carbonate ($CaCO_3$) as the dominating mineral. The fraction of Calcium Carbonate is often greater than 50% (Qasim, 2021). The rest of the minerals can be pyrite, stylolite, quartz, clay minerals, feldspar, and siderite. Limestone can easily be identified because Calcium Carbonate reacts with acid. Limestone is m composed grains from skeletal fragments, marine organisms, corals, or foraminifera. Chalk is a variety of limestone and is composed primarily of shells. Chalk is the variety of limestone that is most present in the Norwegian North Sea. Clay content in limestone is often relatively small; it can be only 1-3%, as reported in Southwest of China (Liu et al., 2019).

In the Norwegian North Sea, limestone is present in the upper cretaceous system. The formations of interest are Ekofisk, Tor, Hod, and Hidra. These formations are in the Central North Sea, Norwegian-Danish Basin, and Southern Viking graben. There is also some limestone present in Hardråde formation in the Horda Platform (NPD).

Core samples from Ekofisk and Tor formation concluded that these formations consist of white to buff, hard and chalky limestone. Stylolite is present in the limestone. Further down in the Cretaceous system and Tor formation, the limestone tends towards platy and soft. There is more clay present in the Ekofisk formation than in the Tor formation. The chalk present in the Hod formation is tan to light brown, soft to firm hardness, and grainy but uniformed textured. The formations usually also consist of beige to brownish mudstones (Bergsland, 1975; Boyce, 1975; Isaksen, 1989; NPD; Phillips, 1971).

Liu et al. (2019) concluded that the fracture-strikes are likely not uniform in these formations, with some fractures intersecting each other. This is likely to cause the limestone to collapse and affecting the borehole stability and increasing the odds of undergoing slugging.

This is due to the fractures are often filled with other minerals. Excessive downhole losses have been proved problematic in chalk formations. When trying to avoid these losses, the drilling programs have often struggled with differential sticking and borehole stability issues (Vickers et al., 2010).

Limestone formation will often have induced fractures which make the formation loss prone. The limestone formation can, in some areas, be much weaker than expected. This can lead to severe losses. Losses like this are likely to occur in formations with shale and limestone present. High Equivalent Circulating Density (ECD) is needed and expected to penetrate reactive shale due to the high specific weight of shale. On the other hand, the limestone is weaker, leading to losses (Doutoum Mahamat Habib et al., 2018).

1.1.2 Sandstone / Shale formations

Sandstone/shale formations are formations of interest due to their potential of downhole losses regarding fragile sand and heavy shale differences. Sandstone is often porous, which increases the change of fluid loss.

Sandstone is a common sedimentary rock that is present in sedimentary basins around the world. Sandstone is composed of grains of minerals or organic material. The mineral could be granite, feldspar, hornblende, orthoclase, biotite and quartz. Quartz is usually the dominating mineral with a percentage of 90% or higher (King).

Shale is a sedimentary rock that is a buildup of compaction of fined grains. The typical minerals in shale are clay and quartz. Shale is fissile and laminated. In that way, it distinguishes itself from other clay-based rocks. It is the most common sedimentary rock in worldwide basins. It appears in various colors, introduced from gray, brown, red, and black (King).

The combination of sandstone and shale formations are commonly featured in the Norwegian North Sea and from the Norwegian Danish Basin to the Horda Platform. The combination is present in different ages and systems, from Neogene and all down to Jurassic. In the Norwegian Danish Basin, the two formations of interest are the Tau and Sandnes formation. The Tau formation is a deep-marine deposit with chiefly shale. The Sandnes formation is a shallow marine deposit with chiefly sandstone. Tau and Sandnes formation are in the upper and middle Jurassic system, respectively. Utsira formation is a deep-marine deposit with primary sandstone. Above Utsira, there is shale present in a marine deposit. Utsira formation is in Southern Viking Graben and Mio Neogene systems. At the Horda Platform, several formations contain shallow marine deposits with sandstone and shale, such as Sognefjord, Cook, and Oseberg formation with sandstone and Åsgård, Sola, and Svarte formation with shale (NPD).

The Tau formation consists of black to dark grey, fissle, organic-rich slightly to non-calcareous shales (NPD, 2021b). The Sandnes formation underneath consists of a white and massive, coarse to very fine-grained glauconitic sandstone. In some parts of the formation, it is interbedded shale and sandstone (NPD, 2021a). Sandstone in the Utsira formation is clear to white and very fine to fine-grained. In some areas, medium to very coarse-grained. Fossil and glauconite fragments are present throughout the formation (NPD, 2021c).

Naturally fractured and normally pressured sandstone may lead to severe downhole losses and increase the possibility for stuck-pipe. The importance of correct pressure profile in shale/sandstone formation is severe when a significant overpressure in the fractured zone increased the risk of stuck pipe and differential sticking.

Asadi et al. (2018) concluded that when having a shale overburden and a sandstone formation underneath. The mud program needed to be optimized to control the risk of kick, minimize shale breakout in the overburden, reduce the risk of mud losses in the fractured formation, and excessive caving’s in the overpressure zone and shear failure.

1.1.3 Coal formations

Coal formation is interesting due to that coal is a weak formation. If a coal formation occurs unexpectedly or has not been considered, a downhole loss is likely to occur.

The most organic-rich sedimentary rock is coal, with Humus as the most organic component. The percentage of carbon present ranks coal. Carbon percentage and compaction determine which type of coal that are present. The types are initially lignite, a brown, very soft coal containing up to 70% water. Then there is bituminous coal, which is softer and containing more carbon than lignite, with up to 69-86 wt%. Finally, there is Anthracite coal which is a rigid and dense rock. Anthracite coal has a black color and has the highest carbon content with up to 86-98 wt%. Coal often occurs in cyclothems of sandstone, mudstone, or limestone (Bowen, 2008; Schwab).

In the Norwegian North Sea, coal is present in the middle Jurassic system. The formations of interest are Bryne formation, Sleipner formation, and Ness formation. The coal in these formations is in costal, deltaic, and flood plain deposits (NPD).

The Sleipner formation has sections with fined grained sandstone with a bed of 10m thick coal on top. The coal is massive, hard, fractured, black, bright, and reflectance in the well completion report from the Sleipner formation (Npd, 2010). A core sample from the Bryne formation consisted of very fine to fine-grained sandstone with occasional coal lamina (Myrland).

Coal cleats, fractures, and regular gaps are one of the main characteristics of a coal formation. The fractures are typically perpendicular to the bedding plane and perpendicular to each other. Losses of drilling fluid in these formations can lead to significant drilling and formation damage. Suppose the pressure penetration is along with the cleats. In that case, there will not be a uniform reduction in effective stress and strength, as it would be if the penetration would be uniform. Penetration along the cleats occurs to a great extend in coals. Bybee (2010a) observed that the pressure drop within the cleats will not occur at the immediate face but rather at some distance. This reduces the effective stresses. The shear resistance at the face declines at a greater rate and advancing such that pressurization leads to failure (Bybee, 2010a). Fluid innovation that pressurizes the coal cleats are described by many publications as a strong contributor to the failure of the rock (Barr, 2009; Palmer et al., 2005; Santarelli et al., 1992). This problem can be avoided by keeping the hydrostatic drilling fluid pressure above the fracture propagation pressure to avoid pressurizing existing fractures (Zhang, 2005).

However, Zeilinger et al. (2010) experienced that coals seem destabilized without lost return, presumably because the cleats were forced opened and extended. The same publication concluded that the dominant mechanism of borehole stability in sandstone and shale are equally relevant in coal. A drilling fluid weight ample to avoid excessive stress concentration above shear failure of the rock must be maintained.

1.1.4 Karstified formations

The process where carbonate offshoots to the earth's surface tectonic movement and is exposed to dissolution by atmospheric water and leaching is commonly referred to as Karstification (Xianzheng Zhao et al., 2018). Karstified terrain is commonly characterized by rock ground, caves, sinkholes, underground rivers, vugs, and barren. Soluble carbonate limestone and dolomite formations are where Karstified formation usually occurs. Moderate to heavy rainfall combined with good groundwater circulation are conditions that advocate Karstification (Britannica, 2016). The secondary porosity given by the karst formation can improve reservoir potential and quality.

Karstified formations are present in the Permian and Upper Paleozoic systems in the NCS. The formation groups of interest are Gipsdalen GP, Bjarmeland GP, and Tempelfjorden GP. They are in Loppa High in the Barents Sea. Alta is a field with carbonate reservoir in Gipsdalen

GP with Bryozoan reefs from Ørn formation and vuggy dolomite from Falk formation. The bryozoan reefs can vary in size and reservoir potential. The bigger ones can have a diameter of 2 kilometers and are great potential reservoirs. Limestones and dolomites dictate the Gotha field reservoir with spiculate layers. The reservoir belongs to Tempelfjord GP and Røye formation. Meteoric Karstification is propulsion of the Gotha reservoir (Breesch, 2019).

Karstified formations lead to well control difficulties since severe losses are a challenge due to difficulties assuming the size of the natural fractures and vugs in the formation. Tangen et al. (2019) concluded after testing the Karstified Carbonate reservoir in the Barents Sea that Lost Circulation Material (LCM) pills and pumping and displacing a high volume of fluid were insufficient in this kind of formation. This well was abandoned due to the lost circulation challenges. This discovery leads to other techniques. The operator used a Controlled Mud Level (CML) managed pressure drilling system in several wells in this area, and no significant technical issues occurred. The capability to drill with continually monitored and real-time pressure during the drilling phase using the CML system and wired pipe gave the operator acceptance. This was especially important when overbalance and accurate riser level was required to avoid high surge and swab effect due to bad weather. A combination of CML and silicate/calcium chloride cement/sodium treatments reduced mud losses significantly. The operators used this system and reported no significant technical difficulties (Tangen et al., 2019). Fossli and Stave (2014) stated in their article that the technology could be used to reduce NPT, improve drilling speed, well length and reduce overall drilling cost. If total mud losses occurs Bysveen et al. (2017) introduced a method, Controlled Mud Cap Drilling (CMCD), to take control of the situation if total mud losses occur. This method's main task is to ascertain that hydrocarbon migration from the wellbore to the surface will not occur. To ensure this, the principle of CMCD is that fluid is injected outside the drill string with sufficient velocity to overcome the velocity of natural gas migration.

1.2 Well construction

A well is build up in different sections, structures, and steel casings. A brief introduction will be given to understand how a well is build up when later analyzing where the downhole losses occur.

To secure and support the well when done is finished, a steel casing is used. The casing should withstand and seal the well from its surrounding formations. The different casings are named by where they are placed in the well.

The casings are commonly named:

- Conductor
- Surface casing
- Intermediate casing
- Production casing
- Reservoir liner

Conductor casing supports the upper section of the well to set a solid foundation and prevent the unconsolidated formation from caving into the well. The length of this section is typically around 50-150 meters.

Surface casing is the following casing with the main task to install the Blow Out Preventer (BOP) before further drilling. This section is commonly 300-1200 meters dependent on the formation drilled.

Intermediate casing is the middle part of the casing program. This casing is set to place the production section at the right spot and depth. Horizontal wells or multilateral wells often start in this section (Kick-Off Point). The intermediate casing protects weak and caving formations and enables different drilling fluids to control further and lower formations. This section can be drilled to 2-3000 meters depths.

The production casing's main task is to set the well above the reservoir section and set the production packer, and secure that primary completion components are installed at the lower part of the production casing. In the NCS, there is a mandatory demand that the casing is cemented 200m above the reservoir with hydrocarbon. The depth of this casing varies, but in the range of 2000-4500, MD is usual.

In the reservoir section, a liner can be used to extract as many hydrocarbons as possible. The liner is flexible and very steerable to maximize hydrocarbon recovery

A well could be drilled in several directions and angles to enlarge hydrocarbon recovery. The placement of the bit and angle of the wellbore are named by inclination and azimuth. Where inclination is the deviation from the vertical direction of the well and azimuth of a directional well is the deviation from the magnetic north (Gooneratne et al., 2017). When analyzing final well reports, losses will be related to the well's inclination. The inclination is typically separated into vertical, deviated, and horizontal categories. *Table 1* Description of well inclination. With vertical, deviated, and horizontal measured in degrees.. All angles are from vertical and in degrees. *Table 2* describes a typical casing program with names, holes, and casing dimensions (Lidal, 2017).

Vertical	Deviated	Horizontal
0-45 °	45-75 °	75-90 °

Table 1 Description of well inclination. With vertical, deviated, and horizontal measured in degrees.

Section	Name	Common hole size (alt. size)	Common casing size (alt. size)
1	Conductur	36’’	30’’
2	Surface casing	26’’	20’’, (18-5/8’’)
3	Intermediate casing	17-1/2’’, (12-1/4’’)	13-3/8’’, (10-3/4’’)
4	Production casing	12-1/4’’, (10-3/4’’), (9-5/8’’)	9-5/8’’, (8-1/2’’)
Reservoir section	Liner or open hole	8-1/2’’	Open hole or 7’’ liner

Table 2 - Description of a common casing program with hole and casing dimensions.

1.3 Drilling fluid

Loss of drilling fluid can be costly, and it decreases the well control and stability. Drilling fluids have different attributes, and the different types found in the final well reports studied will be described. Drilling fluid or drilling mud is a densified and viscous fluid added to the wellbore to stabilize the well, suspend the cuttings, lubricate and cool the drill bit and control the pressure.

Stabilizing the well is done by controlling the Equivalent Circulating Density (ECD) and thereby prevent the inflow of fluids or gas from formation and minimize the risk of creating fractures. Factors like density, viscosity, and flow rate are crucial when controlling the ECD. Another feature of drilling fluid is to carry the cuttings from the bit up the annulus and perquisite separation on the surface. It is vital to suspend the fluid in a well to prevent settling. Drilling fluid viscosity is essential, and in that respect, drilling fluid and its additives is crucial. Forming a thin filter cake is an essential feature of the drilling fluid. The filter cake seals the pore in permeable zones and other openings created while drilling, preventing fluid loss. Another principal function of the drilling fluid is to maintain stability in uncased sections.

Drilling fluid consists of three main components: base fluids, solids, and additives to ad or maintain the properties of the drilling system.

The two types of base fluids used are water and nonaqueous fluids like synthetic or mineral base oil. Water-based mud (WBM) is a system where solids are suspended in water or brine. The system is provided with heavy solids. A saturated brine can also replace the solids. The Use of brines might increase the drilling rate (ROP) and reduce formation damage created by the particles that are not present, but on the other hand, this may increase the cost of the product itself. WBM can have various additives to enhance different attributes. Some logging tools perform better in WBM, and that with the fact that WBM gives lower environmental damage than their alternatives make it a good alternative.

Nonaqueous systems or oil-based mud (OBM) is a system where the particles are suspended in oil. OBM has an advantage of not reacting with the formation, especially when shale formations are present. OBM is often used in horizontal wells when there is gas in a shale formation due to better stabilization capability.. Ghamdi et al. (2017) stated in his article that the cost of logistics and transportation of OBM cuttings offshore is substantial. As WBM, OBM can vary in attributes due to which additives added.

Solids in drilling fluid are primarily used to control the well-pressure and stabilization. Heavy inert high-density material is used, where barite and hematite are most featured. The solids quantity is based on the desired mud weight. Different particle size distribution (PSD) can be used as a sealing mechanism when traveling up the annulus and thereby provide wellbore strengthening and reduce losses. This will be not be discussed in the analysis. However, it can be an explanation why some upper sections are left untreated when facing losses.

Additives in drilling fluid are crucial to control and modify properties like viscosity, chemical reactivity, fluid loss, and lost circulation.

Viscosity is defined by the fluid’s resistance to flow, where high viscosity fluids often are described as thick, where fluids with lower viscosity are described as thin (Caenn et al., 2017). A high viscosity generally increases the ECD and increases the surge and swab pressure. The rate of penetration (ROP) will be affected and reduced with a thicker fluid. Piroozian et al. (2012) concluded in their study that a higher viscosity remarkably increased cuttings recovered, especially in a deviated well. This may reduce the development of cuttings bed and decrease the risk of differential sticking. Viscosity additives in WBM could be Bentonite, Polymers, Thinners, and Deflocculants/Flocculants. Where Bentonite and Polymers also provide fluid loss attributes. In this study, viscosity additives will not be considered as fluid loss treatments, even though high viscosity pill is spotted regularly in the well. Viscosity additives in OBM may be Organophilic clay, Fatty acids, and Sulphonated Polystyrene.

Chemical reactivity additives are added to control events like pH, Clay Inhabitation, Shale Stability, Alkalinity, Contamination Control, and Emulsification.

Additives to control fluid loss are added to the drilling fluid. Wellbore strengthening and Lost circulation are key in the security and cost management of a well. Lost circulation additives are described in chapter *1.6 Lost circulation material*.

1.4 Environmental aspects of drilling and lost circulation

Environmental emissions considerations are hugely vital in the oil and gas industry. There is a demand and a desire to keep the emissions as low as possible. Environmental aspects of CO_2 and NO_x for drilling and running a rig will be discussed. The factors considered are drilling, completion, plug and abandonment, vessels, trips, and outbound and return for a helicopter.

Saasen et al. (2014) outlined an estimate of the environmental impact using a cuttings disposal well and onshore drilling waste treatment. It is estimated that 30 tons per day of diesel oil are used during operation, completion, plugging and abandonment of an oil well. This estimation can vary due to the size of the rig and the time of year. A standby vessel affiliated with the drilling rig is consuming 2 tons of diesel per day. An average of two trips per week during drilling is roughly required during an average field operation, and the supply vessel typically consumes 4 tons diesel per trip. The average number of trips reduces when the well is in standby mode. Lastly, helicopter traffic will be included. Outbound and return for a helicopter count for roughly 5 tons CO_2 and usually 4 flight average per week. Furthermore, the article estimates that 1-ton diesel will produce approximately 3.17 tons CO_2 and 0.07 tons NO_x.

Insufficient hole-strengthening and lost circulation challenges may lead to a higher environmental impact. Losses and loss prevention may lead to an increase in trips, and, as described previously, this will increase diesel consumption. If downtime and total drilling time increase, diesel consumption will increase and thereby CO_2 and NO_x production. In this thesis will be deliberated around these environmental challenges by researching final well reports.

1.5 Classification of circulation losses

Loss of drilling fluid to formation is called lost circulation. The lost circulation of drilling fluid is challenging and a costly problem for the drilling industry. There is spend a massive amount of money on preventing this. It is reported that 20-30% of wells drilled worldwide come across this problem (Economides, 1998). Lost circulation is defined by the absence or reduction of drilling mud pumped through the drill string while drilling the wells, which filtrates the formation instead of flowing up to the surface (Toreifi and Rostami, 2014). Some losses are unavoidable, but every single loss may lead to a substantial financial cost due to other drilling complications that could cost millions of dollars (Kumar and Savari, 2011). Lost circulation may be a vital well safety factor, regarding the increased risk for a kick. In severe cases, lost circulation may lead to abonnement and plugging of the well (Ramasamy and Amanullah, 2018).

Lost circulation may occur at any depth where pressure imbalance is present, and the formation breakdown pressure is less than the total hydrostatic pressure in the well. This usually occurs when the mud weight to stabilize the well is too high and exceeds the formation fracture gradient. During drilling and trips in permeable formations, lost circulation can occur because of the surge effect when lowering drill pipe and casing. The mud level in the annulus will drop and change in the hydrostatic pressure, leading to losses (Suyan et al., 2007).

When considering formation and rock breakdown, horizontal stress is a crucial measure, where horizontal stress equals the average pressure between pore pressure and fracture pressure. The ideal mud weight to enhance wellbore strengthening and control is equal to the horizontal stress. A lower mud weight than the horizontal stress may lead to the borehole collapsing, kick, or a tight hole. On the other hand, a higher mud weight than the horizontal stress may lead to fracture propagation and, thereby, losses. In some models, horizontal stresses are due to compaction only, neglecting tectonic effects and fracture effects. Plate tectonics, salt domes, and faults are global geological processes that affect this. By this, pore pressure, overburden stress, borehole inclination, and borehole azimuth are used to estimate the principal stress, which is horizontal and vertical stress. Considering this, it can be interesting to investigate inclination regarding losses (Aadnoy, 2010).

Formations as limestone, sandstone/shale, coal, and Karstified are loss-prone, as described previously. These formations are possible to observe pressure imbalance due to different reasons. Where limestone is exposed for collapse due to not uniform fault strikes. One main reason sandstone/shale formation is exposed for losses is the pressure imbalance between the dense overburden shale and the weaker sandstone. Naturally, fractured sandstone may also be considered. Fluid innovation of cleats, fractures, and gaps in coal may contribute to rock failure and thereby lost circulation. In Karstified formation, the fractures and vugs' size is challenging and possibly huge and can cause severe losses.

When drilling and circulating fluid in a well, a shale-shaker is used to screen solids from the circulated fluid. Vibration over screens is briefly how the shale shaker works. The screens can have different grid sizes dependent on the size and abundance of solids, circulation rate, wellbore properties, drilling fluid properties, and additives. If the shale shaker is not correctly monitored or set up, it can lead to an overflow and losses at the shale shaker (Committee and Asme Shale Shaker, 2004). Mud losses at the shale shaker will not be considered when analyzing losses in this thesis.

Losses will be distinguished between static and dynamic losses. In theory and this thesis, dynamic losses will be classified as:

- Minor losses/seepage **0-1 m^3/hrs**
- Partial losses **1-10 m^3/hrs**
- Severe losses **>10 m^3/hrs**
- Complete losses

1.6 Lost circulation material

Different methods and strategies are used in the industry to control and prevent lost circulation. In this section, they will be investigated in detail. This is performed to get a background before analyzing methods and strategies used in the final well reports.

Wellbore strengthening is engineering's techniques used to increase the maximum pressure a well can withstand without losses. Feng (2016) stated that wellbore strengthening account for actions such as plugging, bridging, or sealing the fractures where losses occur. Wellbore strengthening can also potentially decrease stuck pipe, wellbore instability, blowout, and kick.

Lost Circulation Material (LCM) is used as a wellbore strengthening strategy to prevent and cure downhole losses. LCM is added continuously to the drilling fluid or as concentrated pills, with the task to seal fractures caused when drilling or naturally existing fractures. The wellbore strengthening strategies can be divided into two groups, preventive and remedial treatments.

Preventive treatments pursuit to reinforce the wellbore and prevent the creation or extension of naturally and pre-existing fractures. Salehi and Nygaard (2011) concluded that today's solutions rely on a proactive mud program using LCM to increase the wellbore hoop stress. However, they concluded in the same study that the wellbore strengthening approach could not increase wellbore hoop stress in the fractured zone more than its ideal or intact state.

A low permeability and high ductility filter cake can be accelerated by LCM additives. Filter cakes have been used in the industry for years and have proven effective for lost circulation in highly permeable formations like sandstone (Feng and Gray, 2017). For fractured formations, coarse particles should be used to bridge the entering of pre-existing fractures. When the bridge is present, smaller particles should be used to prevent fluid loss through the bridge, and thereby a filter cake can be used to seal any drilling-induced or pre-existing micro-fractures on the wellbore wall (Aadnøy and Belayneh, 2004). A low permeability mud cake may enhance wellbore strengthening. Filter cake build-up or properties are time-dependent, where filter cake properties and thickness are functions of time. This unquestionably affects the wellbore strengthening and stress state (Tran et al., 2011).

Remedial strengthening seeks to re-gain the strength of the wellbore after a loss has already occurred. The treatments consist of plugging, bridging, or sealing the fractures that cause loss. Furthermore, the main goal of remedial strengthening treatments is to stop further fracture propagation and increase the maximal pressure the wellbore can sustain without a further loss (Feng and Gray, 2017). LCM as a remedial strengthening method is added to the drilling fluid continuously or as concentrated LCM pills, depended on loss classification. Continually added LCMs in different concentrations are widely used for minor or seepage loss.

When severe or complete loss has occurred, settable LCM pills such as plugs, gunk, cement, deformable or soft plugs are prescribed to solve the problem (Alsaba et al., 2014a).

Feng and Gray (2017) reviews of fundamental studies on lost circulation and wellbore strengthening listed several mechanisms that alone or in combination can enhance the pressure bearing capacity of the wellbore as a remedial treatment.

- Enhance the fracture closure stress by widening and prop a fracture.
- Increase the local compressive hoop stress around the wellbore by bridging the fracture near its mouth. This will enhance the fracture opening resistance.
- Isolate the fracture tip from wellbore pressure to resist fracture propagation. This is done by forming a filter cake in the fracture as close to the tip as possible.

Furthermore, Feng and Gray (2017) listed some more alternative methods.

- Changing the chemical composition of the formation with chemical treatments.
- Forming chemical sealants in the fracture.
- Warming up the wellbore to increase the effecting fracture gradient by thermal treatment.

Changing the filter cake from oil-wet to water-wet to enhance the fracture healing when drilling with oil-based mud by wettability-alteration treatment.

Guo et al. (2014) concluded in their experimental study that a preventive LCM treatment can be more effective than remedial treatment, even though the remedial treatment had twice the LCM concentration. Further, they concluded that particle size distribution and size of LCM are crucial when sealing fractures. After the LCM program is performed and the fractures are induced, the formation is repaired, and further strengthen.

Alsaba et al. (2014a) published an updated classification of today's LCM solutions. Classification is needed to distinguish LCM based on physical or chemical properties. They reclassified into eight categories:

- Flaky
- Granular
- Fibrous
- LCM mixture
- Acid soluble
- High fluid loss LCM's squeezes (HFLS)
- Swellable/hydratable LCMs
- Nanoparticles

Flaky LCM exist in different sizes with a large surface area and a thin and flat shape (Schlumberger, 2021b). Flaky LCM types are capable of plugging and bridging many types of porous formations to stop losses or at permeable formations establish an effective seal (Pilehvari and Nyshadham, 2002). Adaptability and high retention probability are the advantages of flaky LCM. For example, if the width of the LCM is larger than the width of the fracture, will it turn over and retain and form retention (Xu et al., 2019). Flaky materials might include mica, cottonseed hulls, cellophane, calcium carbonate, and corn cobs (Alsaba et al., 2014a).

Granular LCM exists in a various of particle sizes and is chunky in shape (Schlumberger, 2021c). Granular LCM are commonly used in bridging, are effective in sealing fractures, and are cost-effective. These are the main reasons why they are chosen (Lee and Dahi Taleghani, 2020). Furthermore, Lee and Dahi Taleghani (2020) concluded that the effects of granular LCM are strongly dependent on the fracture size measurements and thereby tailor the LCM particles to be equal or smaller than the fracture width. Bybee (2010b) wrote that granular LCMs are very effective alone in bridging fractures less than 1000 µm. However, when the fractures exceed 1000µm, a combination of other LCMs and proper size distribution would be beneficial when aiming to improve bridging efficiency. Granular LCM may include nutshells, graphite, gilsonite, sized calcium carbonate, asphalt, perlite, and course bentonite (Alsaba et al., 2014a).

Fibrous LCM is slender, flexible, and occurs in various sizes, grades, and fiber length (Schlumberger, 2021a). Fibrous LCM can be used in oil-based and water-based drilling fluids. One of the advantages of fibrous LCM is the ability to penetrate deep inside the fracture due to relatively low stiffness. This helps mitigate the lack of knowledge of fracture width, which is crucial for granular and flaky LCM types (Belyakov et al., 2018). Savari et al. (2014) concluded that fibers would improve wellbore strengthening and lost circulation mitigation. The fibrous material may include mineral fibers, nylon fibers, cellulose fibers, shredded paper, and nylon fibers (Alsaba et al., 2014a).

An LCM mixture is a combination of two or all the LCM variations listed above. Advantages with a mixture are the capability to seal a wide range of fractures due to the possibility of wider particle distribution and particle size optimization. Savari et al. (2014) provided some evidence that an LCM mixture is more effective than a single type of LCM. They also concluded that adding some fibrous in the LCM mixture will increase the plug-braking pressure, which is a good indicator for LCM efficiency.

An acid-soluble LCM mix of polymers and acid-soluble minerals is designed to bridge and seal fractures in the production zone without damaging the formation (Prince, 2021). This is beneficial in reservoir sections or production zones, where acid-soluble non-damaging or degradable LCMs are preferred (Savari et al., 2016). Acid-soluble LCM includes Calcium Carbonate and mineral fibers (Alsaba et al., 2014a).

High Fluid Loss LCMs Squeeze (HFLS) is an LCM combination provided to cure severe losses when facing fractured or highly permeable formations by creating a sealing plug (Alsaba et al., 2014a). Dupriest et al. (2008) described that HFLS LCM is based on rapid de-fluidization. The de fluidization is to create a plug to seal loss zones that are not particle size dependent. HFLS benefits are obtained from the mixed material present (i.e., soft, siliceous sedimentary material, fined grind, soft, and other particles yield a small/finer particle size distribution). The mechanism behind HFLS is based on powered siliceous material that reacts with water and forms siliceous acid. Furthermore, the siliceous acids react with the calcium source present in the HFLS mix and form a hard aggregated mass (Savari et al., 2020).

Swellable LCMs are a mix of reactive particles such as polymers. The goal with swelling LCM is to create a barrier between the fluid in the annulus and the formation. First, the barrier created by the LCM will penetrate the loss zone, and thereby swelling and sealing the inner fractures and reducing the flow velocity. This is effective in naturally fractured or vulgar formation (Bermudez et al., 2019).

Nanoparticles are microscopic particles that can access the tiniest fractures, pores, and pore throats. Additives with a size in the range of 1-100 nanometer are defined as nano-based drilling fluid, which physically translates to a billionth of a meter (Amanullah et al., 2011). The particles can perform as a sealing agent in unconsolidated formations to all other lithologies. In addition, nanoparticles can form a very thin, impermeable, nonerodable filter cake, which effectively reduces mud filtrate and mud loss (Contreras et al., 2014). Amanullah et al. (2011) suggested in their study that nanoparticles can play a significant role in controlling loss circulation, reduction in stuck-pipe in highly permeable formations and reduce reservoir formation damage. Furthermore, Zakaria et al. (2012) concluded in the same way that with nanoparticles present, the fluid improved its loss rate compared to conventional LCM due to the particle's ability to block small-sized pores and interact with clay particles.

1.6.1 Lost circulation materials test procedures

Today’s standard testing procedure is published by the American Petroleum Institute (API) Recommended Practice 13-1 or 13-2. Khalifeh et al. (2019) stated in their article that a differential pressure of 100 psi or 500 psi used in American Petroleum Institutes practice is not sufficient to give any meaningful data for LCM performance. In a typical drilling situation, the overbalance needs to exceed 100 psi to avoid influx and control formation pressure. Furthermore, the authors claim that the dynamic differential pressure may exceed 3000 psi when accounting for frictional effects, overbalance, and variations in the formation pressure.

High pressure and high temperature (HPHT) testing conditions are set to 90 degrees Celsius and with a filtration disk, which at a laboratory often has a slot-openings at 500 µm or 250 µm. Alsaba et al. (2014b) concluded in their study that CaCO3 and graphite performance as LCM is not temperature-dependent, which may contribute to why they are so frequently used. It can be discussed that testing at a standard disk whit slot opening at either 500 µm or 250 µm is insufficient. This is due to the actual fracture, and pore openings are often unknown when loss situations occur. The performance of many LCM is very particle size, and pore/fracture size depended, and that substantiates the point. Jeennakorn et al. (2019) and (2017) illustrated that LCMs performance is related to the testing method, and thereby different testing methods will give different results. Where variations in density, weighting material, and base fluid impact LCMs performance.

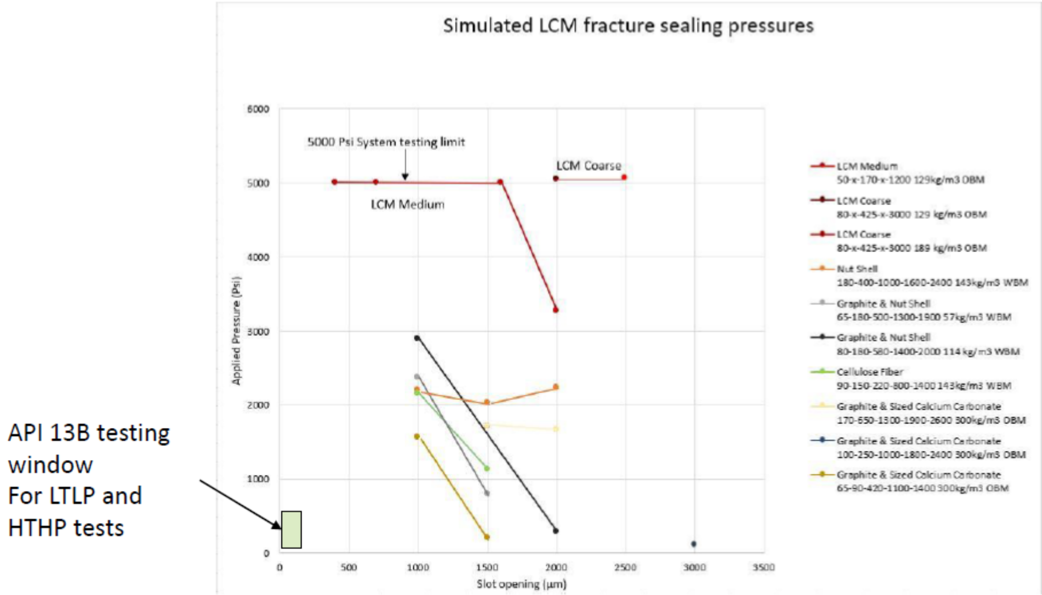
As mentioned previously, particle size distribution (PSD) and understanding the fracture diameter are important parameters when designing LCM. Abrams (1977) designed a criterion that traditionally considering PSD on granular LCM. Abrams' median particle-size D_{50} states that the bridging material diameter should be greater or equal the 1/3 of median pore size of the formation. However, this criterion was shown not sufficient to fix lost circulation challenges during drilling operations.

Furthermore, an ideal packing theory modified Abrams' rule to optimize PSD to formations pore size (Dick et al., 2000). The method was further developed by Vickers et al. (2006), who stated that D_{90} should be equal to the maximum pore throat. Alsaba et al. (2017) introduced a similar criterion to Vickers. The criterion states that D_{90} and D_{50} should be more significant than 120% and 30% of the fracture width.

In practical cases, fracture width, opening, and maximum pore opening is unknown. Therefore, Whitfill (2008) came up with a practical approach. He suggested a criterion that the LCM with D_{50} should be equal to the anticipated maximum opening size. Furthermore, the uncertainties regarding fracture and pore openings may leads to a more standardized LCM strategy. Questions can be raised if an LCM strategy that is not dependent on proper particle size to perform would be beneficial since fractures and pore sizes are unknown.

Khalifeh et al. (2019) presented in a SPE-conference how conventional LCM and Fiber LCM performed when sealing fractures at different pressures and slot openings as *Figure 1-1* indicates. $CaCO_3$ and graphite at different particle sizes, cellulose fiber, graphite and nutshell, nutshell, and different fiber mixtures are tested and compared at different pressure and with different slot openings. The window where American Petroleum Institute Recommended Practice 13-1 does it testing is illustrated in the left corner of the figure. Furthermore, they concluded that high pressure testing facilitates a better differentiation of LCM performance and general development of alternative test methodologies is beneficial.

It is fascinating and obvious that test results for different LCMs will approximately be the same when the testing window is too small to test the LCM properly, to check its abilities and differences. If the test pressure is set too low, everything will pass, and the test will not give any valuable information. Furthermore, the test does not replicate the actual stresses, fractures, and pressures during drilling operations. This is strange when considering the possible cost and environmental savings



Nut Shell, Graphite, Cellulose fibres and Calcium Carbonate data are collected from studies at Missouri University of Science and Technology

SPE-195609 • Drilling Fluids - Lost Circulation Treatment

Figure 1-1 Fracture sealing capability for conventional LCM and fiber LCM. at different pressure[psi]at y-axis and different slot openings[µm] at x-axis.

1.7 Decision flow chart

When choosing the proper treatment before or after downhole losses, an LCM decision flow chart from either an operator or a service company is used. These flow charts are based on former knowledge and experience of LCM, LCM treatment, and drilled formation. Every service company and operator have a unique decision flow chart. Despite this, there are also some similarities. In his book about lost circulation, Lavrov (2016) stated that there is no standardized or universally accepted decision flow chart. Ten different flow charts from two different operators and two different service companies have been analyzed and anonymized. *Figure 1-2* illustrates a decision flow chart from operator A, the nine other decision flow charts are found in the *Appendix*

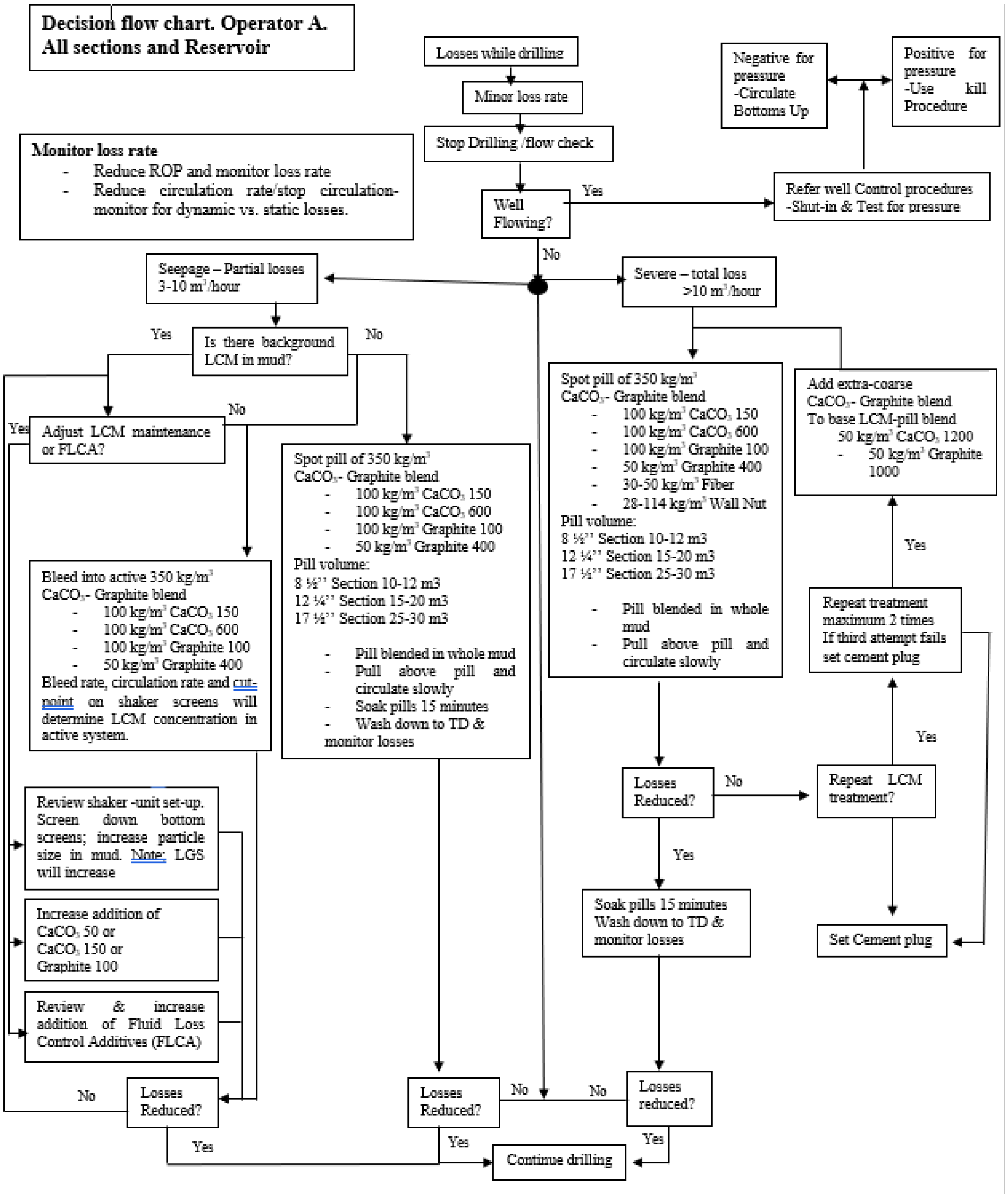


Figure 1-2 Decision flow chart form Operator A

This decision flow chart is taking all sections of the well into account. A decision flow chart is read by following the lines and answer ‘’yes/no’’ on the question raised until the losses are fixed, or the well is plugged. The chart recommends reducing the rate of penetration (ROP) and reducing the circulation rate when downhole losses occur. The flow chart further distinguishes losses in two categories. Seepage-partial losses 3-10 m3/hrs and severe-total losses >10m3/hrs. The following treatment differs such that seepage-partial losses only contain $CaCO_3$ and graphite in different amounts, where some fiber and wall nut are added to the pill when it is severe-total loss. The strategy differs for seepage-partial if there is background LCM in mud, then the $CaCO_3$ and graphite are bled into the active system instead of spotted as a pill. Shake screens, set up, and circulation rate is contributing to the bleeding rate. If the spotted LCM pill is not working as expected, extra coarse $CaCO_3$ and graphite are recommended added to the LCM pill. If treatment fails after the third attempt, a cement plug is recommended.

The decision flow chart has some similarities, especially if we let out the decision flow chart focusing on preventative treatment. Since all other charts are related to remedial treatment, they all distinguish losses somehow, either with static and dynamic or both. Further, the dynamic losses are divided into minor/seepage, partial, severe, and complete. If the charts divide into two, three, or four, categorize varies. All the decision charts have $CaCO_3$ as an additive when having losses. Some add graphite together with $CaCO_3$. Some charts recommend walnut and a little fiber together with $CaCO_3$ and graphite mix. The charts differ more if the first pill did not work. Where some spot the same LCM pill all over again, and some vary particle size and concentration. Consider the number of times a pill is spotted before it is classified as not successful, and a plug is set varies. It varies in the range of three to one pill. Another difference is how some of the charts specify sections where the LCM pill is usable, and some do not. This could be especially important in reservoir sections, where it is crucial not to harm the permeability or affect the production possibilities. The charts differ in how they emphasize drilling parameters like ROP, flow, viscosity, and ECD, among others. In some flow charts, it is stated clearly, and it is not mentioned at all in others. It is fascinating that when the first spotted LCM pill was unsuccessful, the same LCM pill is spotted repeatedly, and that not a broader approach to solving the problem is used. Consider the money and time that can be saved.

1.8 Non-Productive Time (NPT)

Non-Productive Time (NPT) is a measure of all time when drilling activities are interrupted. Non-Productive Time (NPT) is the primary focus considering eliminate drilling and well-related costs. Keeping the NPT at a low level is essential to keep the total cost for drilling a well under control and at a minimum.

An incident that causes the drilling to stop or penetration rate is very low is described as Non-Productive Time (NPT). Incidents like tripping, wearing, stuck-pipe, fishing, tool transportation, and lost circulation can be NPT providers. Krygier et al. (2020) stated that after analyzing 93 Maersk wells from the North Sea, NPT was on average a cost of 2,000,000 USD per well, and losses were the most common cause. NPT is used as a parameter of a wells drilling efficiency, and the target is to keep the NTP at a minimum. Due to the cost of the drilling rig in an offshore drilling operation (rig-rate), controlling NPT is crucial from an economic point of view.

It is interesting to discuss if the race of the lowest NPT could come at the expense of choosing the right solution. For example, the fastest solution may not benefit the reservoir production and performance in the long run. When analyzing final well reports, different operators have their unique way of describing NPT. Some use the fact that if the bit is not working or not producing, it is NPT. On the other hand, some operators use that if they are doing a drilling operation in the well, it is not NPT. Although, they are doing other activities like pulling out of a hole, logging, and others. In that respect, this report will focus on NPT regarding losses and the time used to fix or prevent this.

1.9 Cost

The cost of drilling is enormous. The cost is strongly dependent on the daily rig rate and depth drilled. It will be investigated through final well reports if the cost of lost mud, LCM, or NPT will give the highest cost contribution. When analyzing wells drilled at different years, inflation is considered to even out price differences. An average inflation rate of 2.05% in the last 11 years is used (SSB, 2021). A present value formula (PV) is used to count for inflation, illustrated in *Formula* 1. Where i is interest (inflation) rate and n is number of years from present year.

$$PV = (1 + i)^n$$

Formula 1

2 Objectives

The objectives of this thesis are to investigate the LCMs methods used and their cost, cost of lost circulation, and environmental impact caused by lost circulation. Costs and consequences of changes in casing program and drilling a sidetrack due to lost circulation is not considered.

3 Methods

Information has been collected and found in final well reports and by interviewing drilling professionals. Fifty-six different final well reports from 2009 to 2019 have been analyzed regarding down hole losses, lost circulation material, and non-productive time. Factors like formation type, section, and inclination are considered. In addition, seven drilling professionals from the drilling industry have been interviewed. Some are interviewed several times to get insight and information needed. Due to limited access to final well reports, no reports from coal zones are analyzed. The sections of interest are 12 ¼'' sections and the 8 ½'' reservoir sections. Sixteen wells with severe or complete losses are analyzed in-depth regarding the cost of lost mud, LCM used and their cost, The cost of NPT due to lost circulation, and environmental emissions due to lost circulation. All wells have been categorized into losses classification, inclination and formation drilled. Furthermore, a total of mud lost, LCM used, and time spend because due to lost circulation issues are collected in a database and discussed.

4 Results & discussion

4.1 Formations

Different formations have different downhole loss expectancy. Therefore, losses in the 12 ¼'' and 8 ½'' section was analyzed. There were 38 reported cases of downhole losses in 12¼'' and 8½'' section from 46 wells analyzed.

In *Figure 4-1* we see downhole losses distribution measured in number of losses shown in percentage from formations of interest. The figure illustrates that there are no significant differences in down hole losses between sandstone and Limestone. This may be explained by the small number of wells analyzed, and the fact that some of the wells were located in the same production field.

Losses in Karstified formation was more unusual with 5%, which is natural since the formation does not occur at the same rate as the two others. Equally with limestone compared to sandstone, it is possible that losses in limestone is more likely since sandstone formation are more common.

However, unconsolidated sand was a cause of many losses especially when drilling in Utsira formation. Losses in Grid formation were caused by interbedded sandstone and hard claystone and siltstone. It occurred several times. Losses has a high probability due to the formations different fracture pressure in the interbedded layers.

The Shetland group with different limestone contained formation were accountable for many lost circulation incidents. Induced and naturally occurring fracturs in this kind of chalky formation caused challenges and lead to losses.

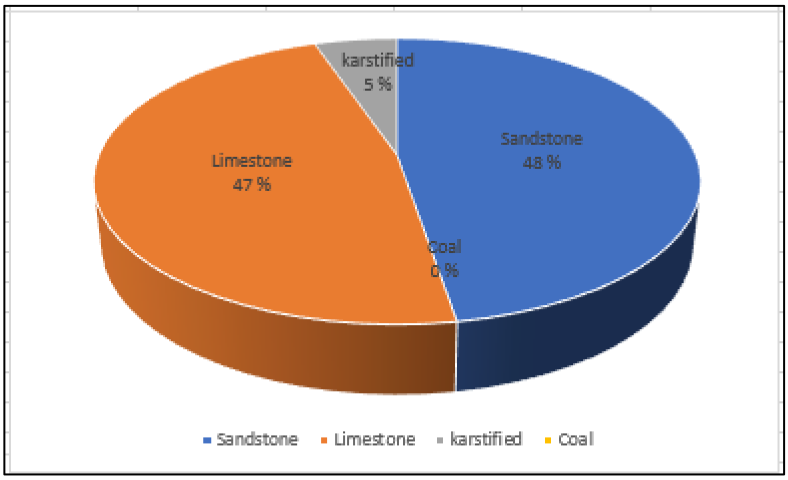


Figure 4-1illustration in percentage in which formation type losses occurred

4.2 Loss type distribution

Lost circulation and downhole losses of drilling fluid is a frequent incident in a well and thereby been analyzed in this thesis. Lost circulation is divided into minor losses 0-1 m^3/hrs, partial losses 0-10 m^3/hrs, severe losses >10 m^3/hrs and complete losses ref. *Classification of circulation losses* chapter. Total downhole losses distribution measured in numbers measured and shown in percentage from the 46 wells analyzed is illustrated *Figure 4-2.*

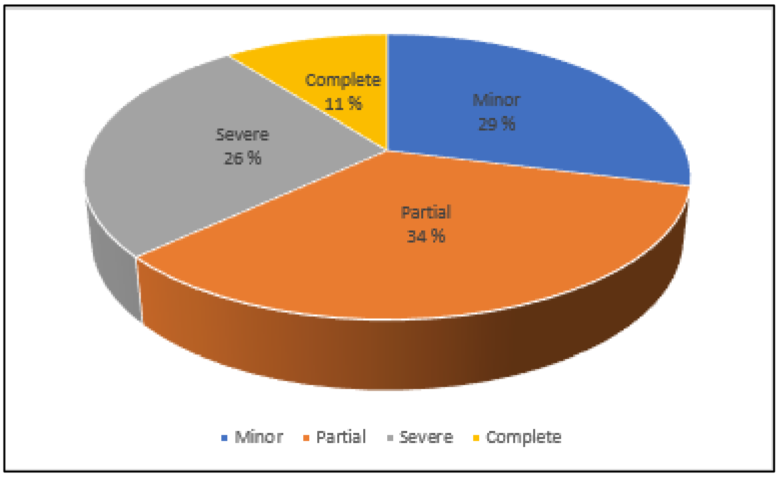


Figure 4-2 Loss distribution illustrated in percentage. Divided into, minor, partial, severe, and complete loss

Partial losses count for approximately a third of losses occurred. In the wells analyzed the losses were relatively evenly distributed. Partial losses accounted for 35%, minor loss at 29%, severe loss at 26% and finally complete loss at 11%. When it comes to minor losses it is questionable if all losses were noted in the final well reports, and especially in porous sandstone where it can be a vague distinction between filtration loss and minor losses. Filtration loss has not been noted.

In *Figure 4-3* illustrates downhole loss distribution measured in number of losses in each category from sandstone formation shown in percentage. The illustration shows that the distribution between minor, partial and severe is fairly even. When we look at the reason which lead to complete losses in sandstone formations, reports indicates that it was due to unconsolidated sand.

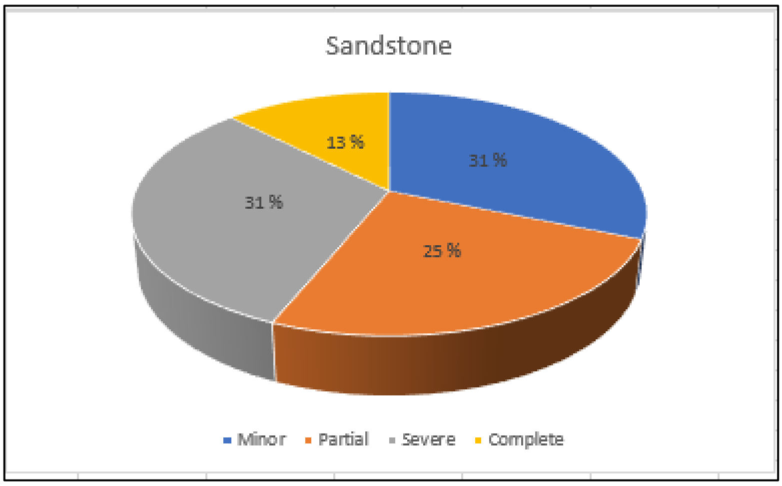


Figure 4-3Loss distribution illustrated in percentage from sandstone formation. Divided into, minor, partial, severe, and complete loss

Figure 4-4 illustrates downhole loss distribution measured in number of losses in each category from limestone formation shown in percentage. Severe losses were accountable for 40% of total losses in limestone formation. Minor and partial losses stood for 27%. It is debatable if the 46 wells analyzed is representative for all wells, but regardless of this it is possible that losses in limestone is greater than sandstone due to the naturally fractures present. If the largely fractured limestone would not have been classified as Karstified formation the percentage of severe losses would have been greater.

Karstified formation was not frequently represented in wells analyzed. Only losses in the high end was reported when Karstified formation was drilled. One well only had less than severe losses when drilling in Karstified formation, this well used CML technology and it is probable that the technology played its part and shrunk losses.

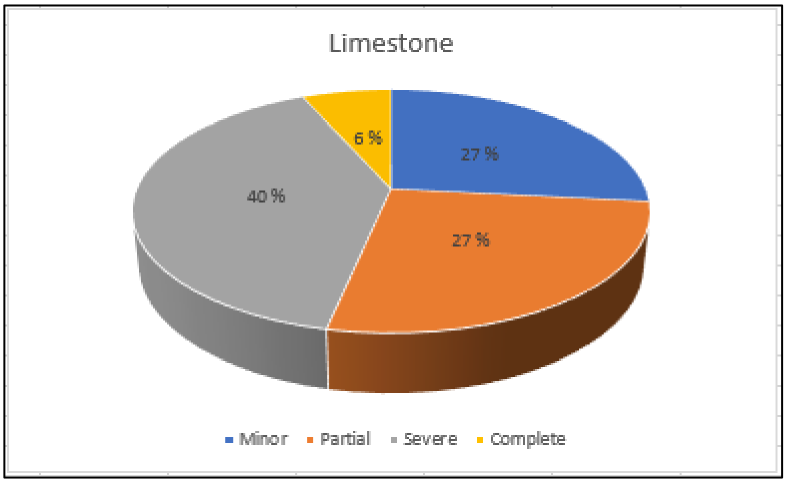


Figure 4-4 Loss distribution in percentage from limestone formation. Divided into, minor, partial, severe, and complete loss

4.3 Well construction

A well is build up by sections and there is interesting to investigate if there are any difference in downhole losses in 12 ¼'' section compared to 8 ½'' section. Losses occurred 27% more frequently in 8 ½'' section than 12 ¼''. This may be a consequence of more detailed reporting in 8 ½'' compared to 12 ¼''. On the other hand, the fact that reservoir section often is sandstone or limestone which is formations that is more prone to downhole losses, compared to 12 ¼'' where all kinds of formation may be present.

In *Figure 4-6* and *Figure 4-5* we see loss distribution of number of losses of each category in percentage divided with loss classification for 12 ¼'' and 8 ½'', respectively. In the 12 ¼'' section partial losses are the most commonly with 44 %. Severe losses with 25%, finally minor losses and complete numbers at 19 and 12%. In the 8 ½'' section minor losses accounts for 37%. Partial losses were accountable for 27%, and severe and complete numbers at 27 and 9%. The increase of minor losses in the 8 ½'' section may be a case of better reporting and a clearer distinction between filtration loss and lost circulation.

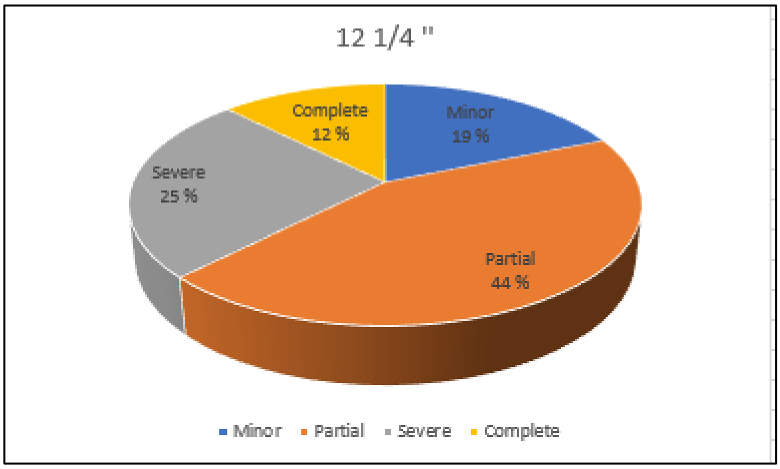


Figure 4-5 Loss distribution in 12 1/4" section showed in percentage. Classified in minor, partial, severe, and complete.

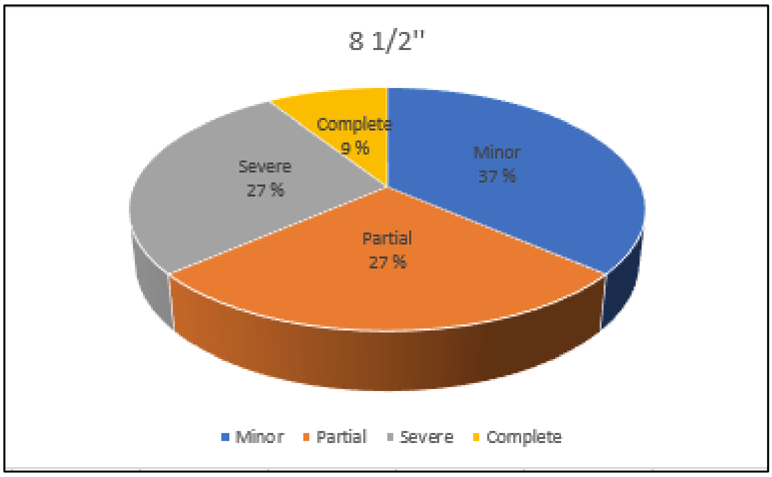


Figure 4-6 Figure 6 5 Loss distribution in 8 1/2'' section showed in percentage. Classified in minor, partial, severe, and complete.

4.3.1 Vertical, deviated & horizontal

A Well's sections may be vertical (0-45°), deviated (45-75°), or horizontal (75-90°). Lost circulation is analyzed and categorized in the three scenarios above.

Most of the wells analyzed had losses in the vertical section. The loss distribution was fairly evenly distributed between minor, partial, severe, and complete losses in the vertical section. A few wells had losses in the deviated and horizontal sections. It is observed here that losses in the deviated and horizontal sections may indicate more significant losses since only partial, severe, and complete losses occurred in these sections. This may be explained by that a more horizontal well will spend more time in loss zones, thereby contributing to more significant losses.

4.4 Lost circulation material and cost

To control, prevent and fix lost circulation challenges lost circulation material (LCM) is used. The different product used in the 16 wells analyzed with severe losses and cost of these product are discussed.

There is in average used slightly under 33 tons of LCM on each well in the 12 ¼'' and 8 ½'' sections when severe losses occur or are predicted. Calcium Carbonate ($CaCO_3$) is the most frequent additive used and is chosen alone or in combination with either graphite and/or cellulosic material. There is at average used LCM products for around 0.28 MNOK. Approximately 15.7 tons in average of $CaCO_3$ is added in each well at the average cost of 0.08 MNOK/well. Information needed for analyzing in this thesis has been challenging to collect due to varying reporting quality and difficulties to get a hand on reports. Some LCM pills are reported with full product name, number of pills and amount of product used. In others reports most of the information is missing, and in these cases the company's fluid decision flow chart is used to predict what kind of pill which was used. *Figure 4-7* illustrates the weight of LCM added to the well when severe losses occurs shown in %.

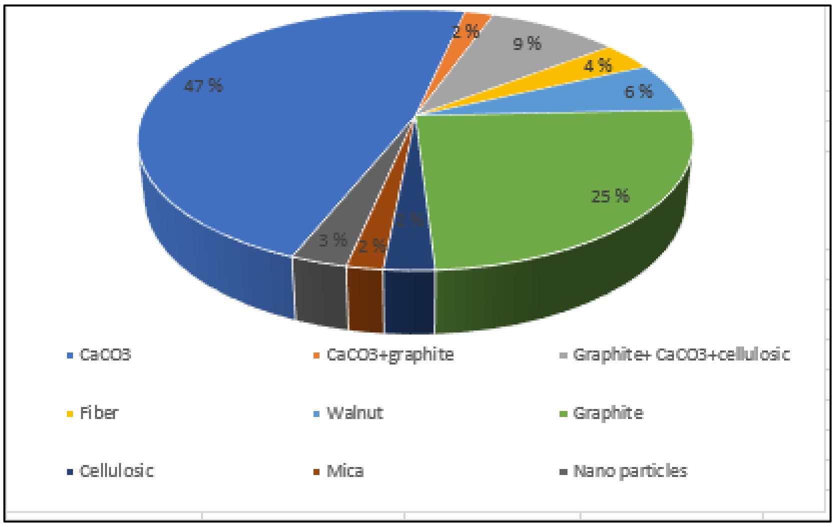


Figure 4-7Illustration of the amount of LCM added in well with severe losses, showed in %

47% of the additives is $CaCO_3$ with graphite as the runner up with 25%. Graphite and $CaCO_3$ is frequently added together in the same LCM pill to enhance sealing probabilities. Alsaba et al. (2014b) showed in their study that a conventional treatment like a combination of graphite and $CaCO_3$ had greater sealing success than graphite and $CaCO_3$ had alone. The same study concluded that temperature had zero effect on graphite and $CaCO_3$ performance. This may contribute to the wide use of these products. On the other hand, the study concluded that fibrous material showed greater success than conventional LCM when sealing tapered discs. Hoxha et al. (2016) concluded in their study that shearing decreases the diameter of $CaCO_{3,}$ a reduction of 25-40% after 30 mins of shearing is found. This may lead to that the PSD of the LCM spotted is not the same as first presumed. This again leads the question why it is so frequently used. Although, not all drilling fluid is exposed to shearing it may be a challenge when circulating $CaCO_3$ as preventative treatment. The numbers show that as much as 74% of the treatment was through the use of $CaCO_{3,}$ graphite or a combination of both. Olsvik (2021) implied that graphite and $CaCO_3$ was frequently used due to the easiness with less inventory needed. Graphite + $CaCO_3$ + cellulosic mix is at 9% and walnut is added at 6%. The additives that is added less frequently is fiber at 4% and nano particles at 3%, $CaCO_3$ + graphite, and mica at 2%.

The product-cost of LCM products varies between 5 NOK/ kg and 35 NOK/ kg, with $CaCO_3$ as the cheapest and graphite as the most expensive. *Figure 4-8* shows the product that was used with generic names and price pr. kg for each product. This information is collected by interviewing professionals from the drilling industry. Product price will vary dependent on the company that provide the product. An average price is used where different prices are collected. The price of nanoparticles was not possible to be found and is therefore left out of the chart.

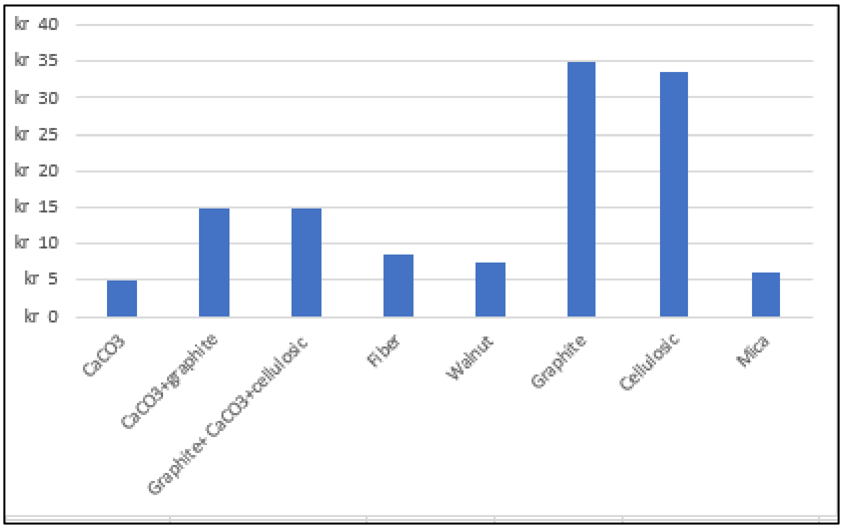


Figure 4-8 Illustration of the price pr. kg of product used in well where severe losses had occurred. Price in NOK on y-axis and generic product name on x-axis

When considering money spent on products treating losses graphite is the featuring product used with 60% of the total product cost. $CaCO_3$ accounts for 16% of the total product cost. Graphite + $CaCO_3$ + cellulosic takes 10% and cellulosic material is at 6%. Walnut, fiber, graphite + $CaCO_3$, and mica with 3%, 2%, 2% and 1% respectively. This is illustrated in *Figure 4-9*

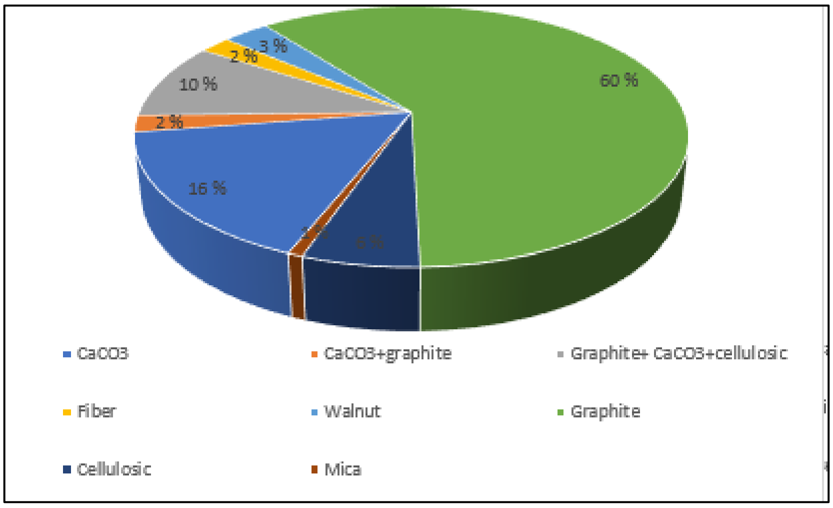


Figure 4-9 Illustration the % of the total cost of each LCM added when severe losses had occurred

Considering the types of formations drilled, there were no difference in product used, or how they planned their LCM. The decision flow chart indicated no difference in strategy depending on formation. Only when CML was present in Karstified formation the strategy was differing. With less or no other product than CML used. It is therefore worth questioning why the treatment does not differ when considering the possible and most likely difference in pore size and fracture openings in different formations. Nanoparticles is not frequently used, and it is questionable if it could be a sufficient option regarding that is proven more effective to reduce downhole compared to conventional LCM. This is loss due to the particles abilities to block small-sized pores and interact with clay particles.

Considering Abram's rule, and its modification that states that knowing and predicting fracture size and pore opening is crucial for the LCMs performance. Thereby it is strange that the strategy does not differ more when drilling different formation types. As a result of the different pore and fractures present in different formations.

LCM selection was often different when comparing the 12 ¼'' and 8 ½'' section. In the reservoir section (8 ½''), $CaCO_3$ was preferred, possibly due to acid solubility. When they differ their treatment in reservoir section, graphite was left out of the LCM pill in the section.

The method used when first treatment was unsuccessful was mostly to either spot the same LCM pill with same ingredients, concentration, and particle size or to add more coarse or fine particles to the LCM pill. The ingredients in the second LCM pill was very rarely changed. It is notable that the LCM pills ingredients is not changed when the first attempt fail, or that at least some other materials is added to create a more broad-spectrum treatment.

Another method of controlling losses is Controlled Mud Level (CML) which cost in average 0.03 MNOK per hour. The cost of each well showed in *Figure 4-10* is in average 10.9 MNOK.

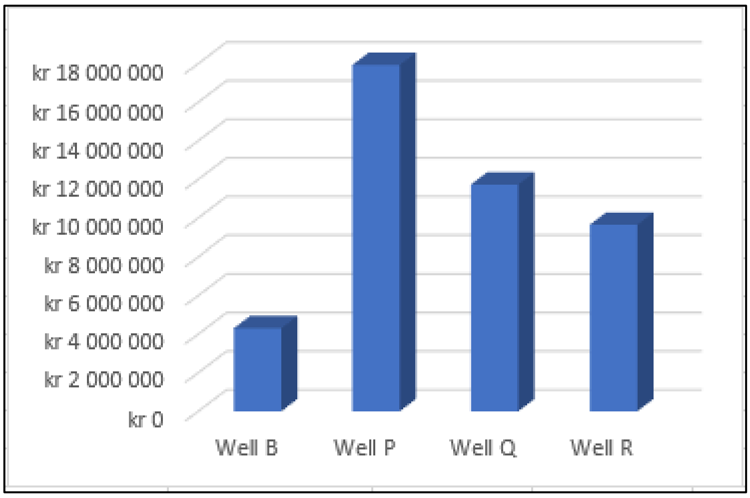


Figure 4-10 Illustration of cost for the four well using CML technology. With NOK on x-axis and well name on y-axis

This technology was proven effective in three out of four wells since almost zero losses was seen on the three successful cases. Well B had low CML cost, but at this well the CML operation was not successful as severe water-based mud was lost. In 12 ¼'' section 90 % of mud was lost and well was plugged and cemented. Despite, the lack of success and the fact that well was cemented the CML cost low were kept low, due to reduced drilling time. In well P, Q and R the CML cost was significantly higher. Minor fluid losses occurred although challenging formation with high loss expectancy was drilled. Although CML is an expensive technique it may be a preferred option if losses are expected to be significant.

4.5 Drilling fluid loss cost

During lost circulation incidents, drilling fluid is lost. Downhole losses of drilling fluid is a well control threat and inflicts the operator a great amount of cost. Drilling fluid lost and their cost is analyzed from the 16 wells with severe losses.

Based on interviews Oil Based Mud (OBM) cost in average 8 000 NOK per m^3 and Water Based Mud (WBM) cost in average 2 000 NOK per m^3. Drilling mud lost in wells are found in final well reports from the 16 wells with severe losses. Fluid losses are reported very differently. Most of the reports report dynamic losses (m^3/hrs), some only static losses, and some of the reports both. Total drilling mud lost is occasionally reported. When it is not reported as a total, total lost each day is added total if daily drilling program is present in the final well report. If only dynamic losses are present an estimate based on time drilled is made to make a drilling mud loss assumption.

An average of 500 m^3 is lost in wells with severe losses and the combined loss in the 15 wells was slightly below 7500 m^3. The total cost of lost drilling fluid is based on the amount of fluid lost and especially the type of mud used, with OBM four times the price of WBM. There is at average lost slightly above 800m^3 of drilling mud in wells were severe losses had occurred. *Figure 4-11* shows the total cost of mud lost. Information was missing in well M.

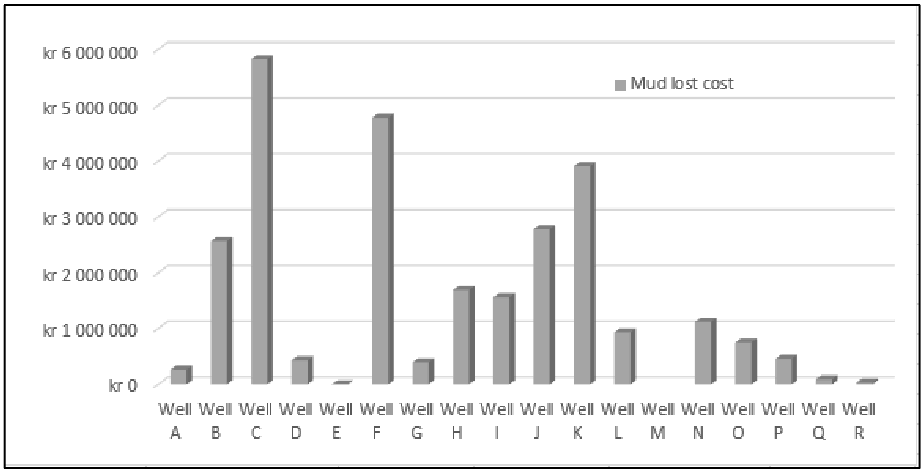


Figure 4-11 Illustration of total cost of mud lost. With cost in NOK on y-axis and well name on y-axis

It is interesting to see the cost range, where at some wells mud lost is nearly dispensable. Well P, Q and R where CML was active and successful and had a low cost of lost mud. Well C and F had the highest lost mud cost was drilled with OBM. They lost 730 m^3 and 600m^3, respectively. Well J and K had the highest amount of fluid lost with approximately 1400m^3 and 1950 m^3, respectively. These wells were drilled with WBM.

Fluid losses varies a lot throughout the wells. It is interesting to discuss whether it is because treatment in some wells were more successful, or if a lack of reporting is the cause since all wells had severe dynamic losses (>10 m^3/h). There are different strategies when mud losses occur. Some operators continue their operation with losses continuously. This differ from other which might plug and cement instead. Significant mud losses also cause other problems than increased cost. The most severe is an increased risk of wells instability and in worst case a blow out.

4.6 Non-Productive Time cost

Non-Productive Time (NPT) is used as a measure of a well's efficiency. An NPT analyze is performed on the wells with severe losses. Rig cost are found in cost sections in final well reports and based on this a cost per hour is calculated. The wells analyzed had an average of 0.3 MNOK per hour. This cost varies from Well C with 0.4 MNOK to Well R with 0.2 MNOK. Non-productive time is found in final well reports. If it is not specified in the report and a daily drilling report was present in FWR, the hours regarding lost circulation is added. If daily drilling report was missing as well and no other significant incident was reported, NPT for the whole section was used. *Figure 4-12* shows NPT cost of wells with severe losses.

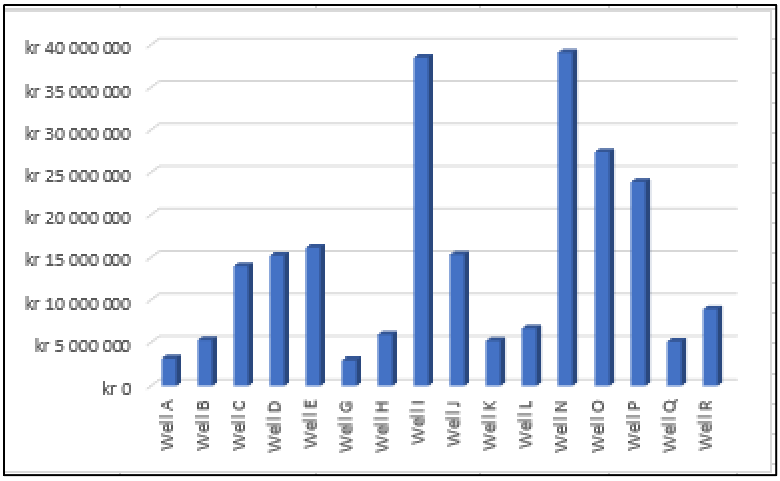


Figure 4-12 Illustration total cost of NPT for wells where severe losses had occurred. Price in NOK on y-axis and well name on x-axis

The Wells I and N stands out with the highest NPT cost with 38.5 MNOK and 39.1 MNOK, respectively. Well A with 3.2 MNOK and Well G with 3.0 MNOK were the only wells with NPT cost, below 5 MNOK. The fact that Well I, N, O and P had severe losses in the 8 ½’’section may strongly influence NPT. Since the 8 ½’’ reservoir section, were hitting the reservoir at a specific height and angle is crucial. Because of this the operators may accept a higher NPT to control and solve possible challenges from lost circulation.

When seeing the huge cost per hour, it is possible that a race for a lower downtime can influence decision and quality on operations. For example, it may be decided to drill with very little overbalance to reduce casings and extensive trips, which again may increase risk of lost circulation.

NPT noted may be higher than observed in final well reports. From interviews it was indicated that other activities were performed to cover the NTP. Instead of noting NPT the well circulated fluid while trying to find solution to the loss problem. This may be driven by kind of a competition between the different companies drilling the well to have the lowest NPT contribution. Illustrated by a pie chart, that is often find in the final well reports, where percentage of NPT divided among the different companies which contributed to the drilling process.

4.7 Diesel Cost

Diesel cost from lost circulation is proportional to non-productive time. Information written in chapter *1.4* is used to make a diesel consumption each hour related to lost circulation (NPT). From interviews, diesel cost is found to be 6 000 NOK per ton. Consumption details is found in *Table 3*.

Event	Diesel consumption [ton]
Rig [day]	30
Vessel [day]	2
Trips [2 times per week]	8
Helicopter [4 times per week]	20

Table 3 Average diesel consumption for events on a rig

The average diesel cost for wells with severe losses were 0.6 MNOK, with big differences. Well N with the highest cost at 1.2 MNOK, while Well A only has the cost of 0.1

MNOK. A figure of Diesel cost for each well related to NTP because of losses are seen in *Figure 4-13*.

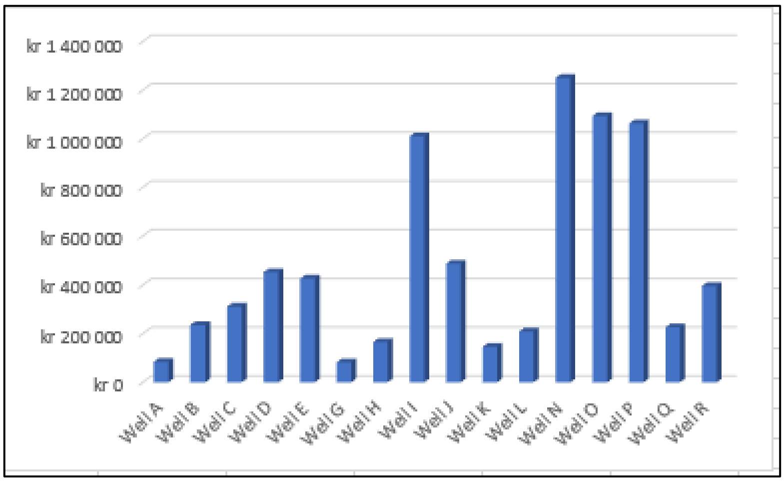


Figure 4-13 Illustration of diesel cost of wells with severe losses. NOK on y-axis and well name on x-axis

4.8 Total cost due to lost circulation

The total cost due to lost circulation is a combination of NPT cost, the cost of lost drilling fluid, diesel cost and LCM cost. The average cost of wells where severe losses occurred was 19.5 MNOK, with huge differences between the top and bottom total cost. Well P and N were at the higher end with 43.7 MNOK and 41.6 MNOK, respectively. In the bottom half is Well G with 3.5 MNOK and Well A with 4.3 MNOK as their total cost. Visibly, there is a huge different in cost, which substantiates the point that lost circulation is an important and possibly costly problem. Total cost of each well that experienced severe losses are shown in *Figure 4-14* The figure is showing total cost and cost distribution from mud lost, CML, LCM products, diesel, and NPT.

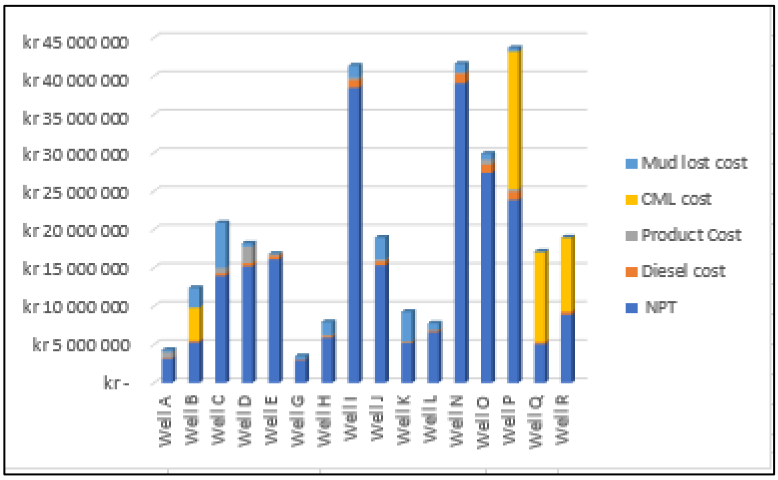


Figure 4-14 Illustration total cost of each well with severe losses. Categorized into Mud lost cost, CML cost, Product cost, Diesel cost and cost of NPT. NOK on y-axis and Well name on x-axis

NPT is the dominating factor and is accountable for 86% of total cost when CML is not present. Mud lost is accountable for 9% of total cost. Product cost and Diesel cost is accountable for 2 and 3%, respectively when CML is not present. This is illustrated in *Figure 4-15.*

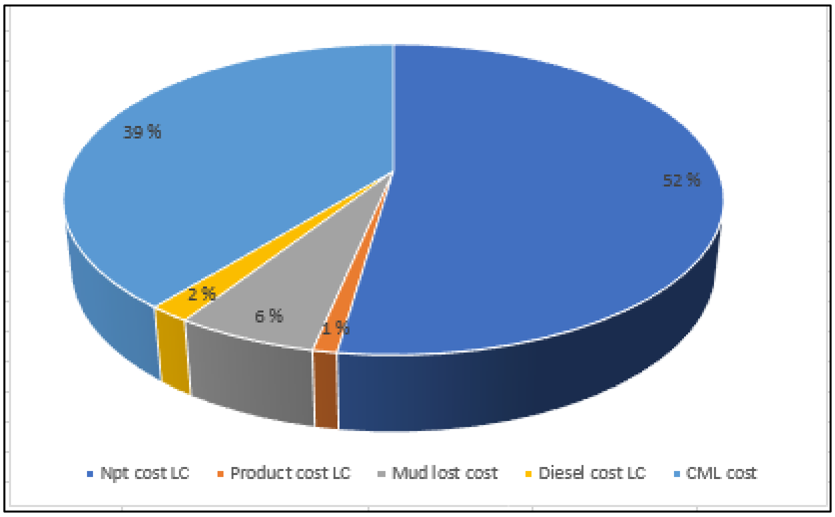


Figure 4-15 Average cost distribution due to lost circulation showed in % without CML

CML is an unusual technique to use. According to the analysis it was present in 8 % of the wells analyzed, however it is believed that the actual number is lower due to the fact that 3 of the wells with CML was from the same production field.

We see that product cost is low compared to the dominating factor NPT. In the avarage total product cost of a well (0.28 MNOK) is roughly equal to the avarege cost of an hour (0.27 MNOK). The wells lost on average 52.6 hours to lost circulation with an average cost of 14,5 MNOK, which is above 50 times the cost of LCM. Why is it not being invested more in preventive products or trying different strategies when there is huge amount of money to be saved is a question to be raised. A more preventive strategy could work like an insurance, and it is strange that this is not a common strategy. As mentioned in the *Lost circulation material* chapter, Guo et al. (2014) backed up that claim by concluding that preventative LCM could be more effective than remedial LCM treatment, even if the concentration of remedial LCM was twice of the preventative.

When considering Alsaba et al classification of LCM, it is interesting that the variation of product used is very limeting. It might be because experience over the years has concluded that todays' strategy has been the most coviniant and cheapest, and thereby is the perferred method for dealing with losses. Contriary to this it is debateable that a better testing procedure will decrease NPT and thereby decrease the total cost caused by lost circulation.

Considering product cost and the strategy used if the first LCM pill fails, it is strange that not a wider approach of particle sizes is used. If preparing and spotting a new LCM pill creates more downtime it would be beneficial to use a wider approach at first.

However, the product strategy used could partially be explained by tradition, by product cost comparison and by the possibility to acid-wash if problems or permeability is damaged. Traditionally one has always tried to solve these situations this way. $CaCO_3$ and graphite has worked to some extend over a long period of time, and therefore the choice to use this strategy on the rig and in the decision flow chart will rarely be criticized. Considering the choice of LCM, it can be speculated that the purchasing manager will compare product prizes exclusively when deciding LCM instead of the possible bottom-line savings. Arguably a product can cost a lot more than it does today, and still be the chosen alternative, if it is proven to reduce NPT.

Another perspective on LCM choice is the test procedures for LCM, and it is possible that an insufficient testing regime leads to a lack of product development. As discussed in *chapter Lost circulation materials test procedures* the APIs test procedure will possibly give the same result regardless of LCM tested, and not distinguish the LCMs abilities. This may cause that product cost is the decisive factor when choosing treatment, since the different LCMs test results is roughly the same.

The average cost distribution was different when CML is considered. Still NPT alone accounts for 52% of the cost. CML accounted for 39% of the costs, the cost of mud lost was 6% and diesel and product were shrunk to 2% and 1 %, respectively. This is illustrated in *Figure 4-16.* In two of the wells with CML it can be argued that CML has a positive effect on the total cost, as long as NPT is kept low because of the use of the technology. This is supported by the Fossli and Stave (2014) article which states that the technology can reduce the overall drilling cost. Another positive thing about CML, seen from an economical point of view, is that the cost is depending of hours drilled and not NPT, which can make the reporting more precise. This is due to the fact that no company will stand accountable for the NPT, and the reporting may be affected by this.

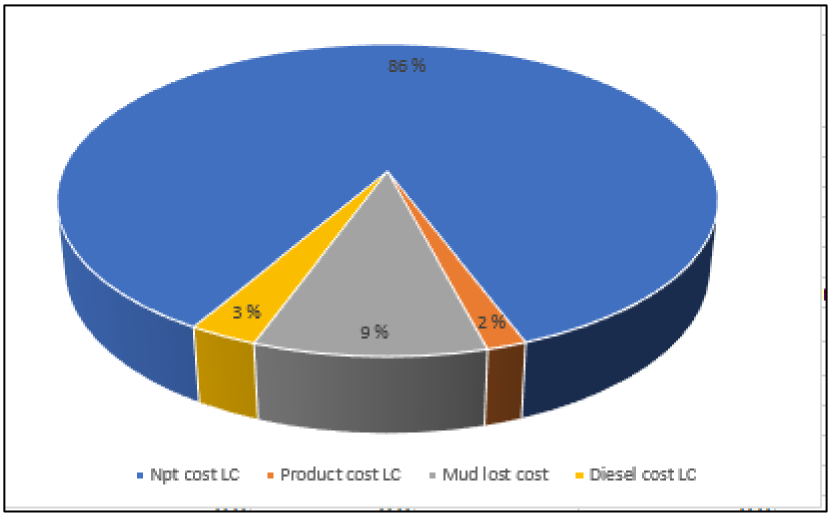


Figure 4-16 Average cost distribution due to lost circulation showed in % with CML

4.9 Environmental emissions

Lost circulation affects the environmental emissions from a well. Total emissions in tons per 1 ton diesel is seen in *Chapter 1.4* and replicated in *Table 4*

	CO_2 [ton]	NO_x [ton]
1 ton Diesel	3.17	0.07

Table 4 Total emissions from 1 ton Diesel in CO2 and NOx

As we see from *Figure 4-17,* the largest emissions in tons of CO_2 are from Well K and P with roughly 4700 and 5200 tons of CO_2, respectively. At the lower end we have Well G and Well H with approximately 1700 tons. In average 2950 tons of CO_2 is discharged due to lost circulation emissions from wells where severe losses have occurred.

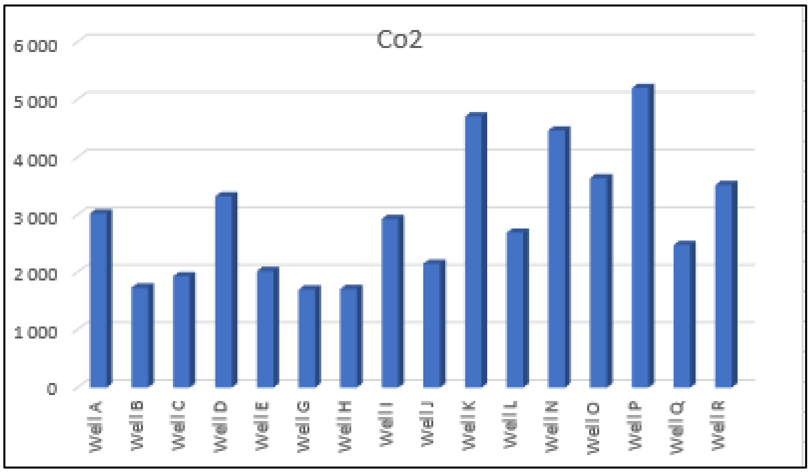


Figure 4-17 Co2 emissions caused by lost circulation showed per well with severe losses. Ton C02 on y-axis and well name on x-axis

The emission of CO_2 is proportional to hours lost due to lost circulation (NPT). The same accounts for NO_x emissions as seen in *Figure 4-18*. Since NO_x also is proportional with NPT, Well K and P has the highest emissions with roughly 330 tons and 360 tons of NO_x, respectively. The same is the case for Well G and H with 120 tons of NO_x. On average slightly above 200 tons of NO_x is discharged due to lost circulation emissions from wells where severe losses have occurred.

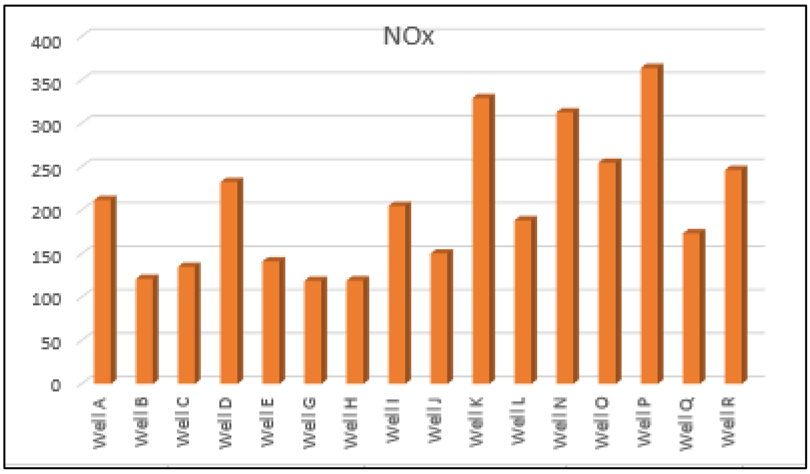


Figure 4-18 NOx emissions caused by lost circulation showed per well with severe losses. Ton Nox on y-axis and well name on x-axis

Figure 4-19 illustrates the percentage of total emissions in a well with severe losses. This is calculated by dividing total emissions from total drilling time with emissions due to lost circulation.

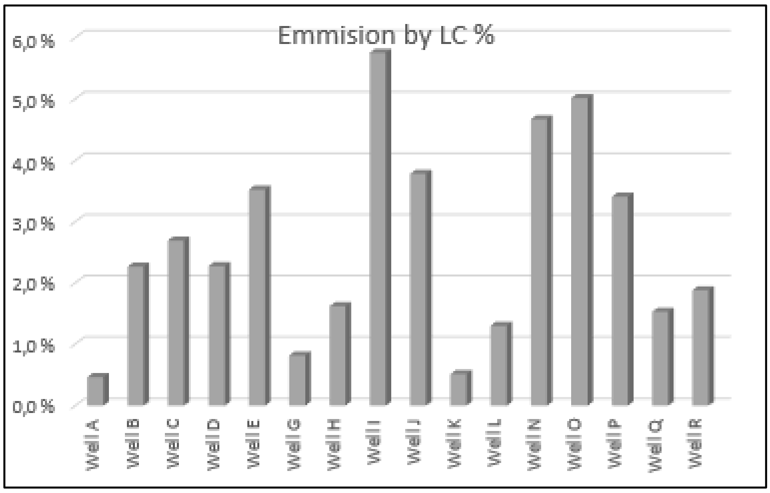


Figure 4-19 Total emissions in % caused by lost circulation in wells. Percentage of total on y-axis and well name on x-axis

The numbers show that there is a wide spread from Well A at 0.5% to Well I with 5.8 %. Lost circulation is important when considering emissions and environmental impact since it in average accounts for 2.6% of the total emissions from a well. When analyzing final well reports there was no information regarding this, although emissions was mentioned regarding fluid and additives used.

Total emissions from Norwegian Oil and Gas industry was in 2019 14 million m^3 CO_2. Which counted for 31% of the total emissions divided between the different sources. Transport and industry processes was the following with 25% and 17%, respectively. In the EU, the average emissions from the Oil and Gas industry counts for only 6% of the total. The Norwegian government will increase the cost of the CO_2 emissions so that in the year 2030, 1 ton of CO_2 will cost 2 000 NOK. As a consequence, although we don't know by how much, emissions of CO_2 will increase in cost (miljødepartament, 2020).

If the Oil and Gas industry shall be up and running in the years to come, emissions caused by lost circulation must be taken seriously and it is unknown if emissions regarding lost circulation is considered as a contributor when emissions are sought to be reduced.

4.10 Reporting styles

4.10.1 Lost Circulation Material reporting style

When analyzing final well reports, different reporting styles were observed. Especially when searching for lost circulation material. When reporting LCM pills the difference was noticeable. Examples of reporting styles is illustrated and explained in this chapter. The style of reporting is been classified into good, medium, less good and poor quality.

Figure 4-20 shows a good quality LCM report regarding a spotted LCM pill. The report consists of the specific gravity, weight, and density of the LCM pill. The report regarding the LCM pill defines the weight of each product added with particle sizes specified. This is regarded as a good quality report based on the complete description of material and amount used. The possibility to replicate and learn from the report is present and could be especially important when drilling wells nearby.

Pill nr 1. 1.2 SG 12kg@ 350 kg/m^3
75 kg Product A 600
13 kg Product A 50
108 kg Product A 150
100 kg Product B 100
50 kg Product B 400

Figure 4-20 A good quality of LCM report.

In *Figure 4-21* we see a medium quality report where total weight and density is described, but weight and particle size description of product added is missing. This LCM pill is categorized as a medium quality LCM report due to the challenge of replicating the pill. This is largely due to the fact that specific particle sizes are not present.

Pill nr 1. 10kg @ 350 kg/m^3
Various grades of Product A and Product B.

Figure 4-21 Medium quality LCM report.

In *Figure 4-22* a less good quality LCM report. The only thing mentioned is weight and density of an unknown product. This reporting style is classified as a less good LCM report due to the lack of product name and due to the lack of information regarding particle size.

Pill nr 1. 14@370 with unknown content.

Figure 4-22 Less good quality LCM report

Furthermore, we see in *Figure 4-23* we see a poor quality report. All information, apart from a very general description of particle sizes is missing. This LCM pill is categorized as a poor quality LCM report due to the lack of Product name reported. A specific particle size added is not specified other than that fine and course LCM is used.

Pill nr.1. Fine LCM and course LCM.

Figure 4-23 Poor quality LCM pill report

Lastly, there are reports where nothing is reported at all. This is obviously a problem when learning and passing on information to other wells. When noting is reported at all, it is impossible to know if the treatment used worked or not.

Due to the fact that the lost circulation problem is causing a lot of problems, and has a potential huge cost, it seems strange that a standard method for reporting is not required. It is hard to make progress in this field and learn when the reports are not providing any information. It feels like the reporting style and preference is decided by the person writing it instead of according to a standard procedure, since the reports varies a lot even when they are written by representatives of the same operator. Furthermore, a more consistent reporting style would change LCM selection, and in which formations the different additives performs or not.

4.10.2 Mud lost reporting style

The reporting of drilling mud lost is being done differently in different final well reports. Two different reporting styles are shown in *Figure 4-24* and in *Figure 4-25*. In *Figure 4-24* the report is done with daily drilling report added.

280	23:45	00:00	0.25	PR2, DRL	TRIP	BHA	PT		Pulled and racked back HWDP. Total 32,5 m3 lost in the last 24 hours.

Figure 4-24 Mud lost reporting when daily drilling report is present

The total mud loss during the last 24 hours is noted and thereby making it possible to add total mud lost in sections. *Figure 4-25*shows a good report when daily drilling report is not present. However, the total mud lost in each section is noted first in the section summary.

Fig. 4.8 summarizes the key figures for the drilling of the 17 1/2" section and running the 13 3/8" casing. Total volume lost during this section: 728 m^3.

Figure 4-25 Mud lost reporting without daily drilling report

A problematic fact in many reports is that they do not report total mud lost. They only report dynamic and static losses. It can be argued that total mud lost can be an indication of well stability and control, and for that reason it is important that total mud lost is specified.

4.10.3 Non-Productive Time reporting style

Non-Productive Time (NPT) is a central part of any final well report and can in many ways be a measure of a drilling operations' success. The quality of the report is largely down to whether a daily drilling report is added to the final well report or not. A good quality NPT report is seen in *Figure 4-26,* where a brief description of what caused the NPT is added and noted with an NPT code.

NPT Description	Duration (hr)	NPT code
Down Time Due To Down Hole Equipment Failure	1.00	DHEF
Down Time Due To Well Control	3.50	WC
Non Productive Time	7.00	NPT
Down Time Due To Surface Equipment Failure	9.50	SEF
Down Time Due To Service Company	27.50	SC
Wait On Weather	29.00	WOW
Down Time Due To Stuck Pipe / Casing / String In H	43.00	SPH
Down Time Due To Drilling Contractor	66.50	DC
Down Time Due To Poor Hole Condition	101.00	PHC
Down Time Due To Lost Circulation	125.00	LC

Figure 4-26 Good quality NPT report

The most frequent, and a more general, reporting style of NPT is shown in *Figure 4-27*. No description of what caused the downtime, solemnly the hours, is noted.

Operational time:	157.5	6.6
NPT:	43.0	1.8
WOW:	0.0	0.0
Total time used:	200.5	8.4

Figure 4-27 Medium quality NPT report

A good quality report may contribute to better understanding of drilling challenges and lead to less complications in the future. A detailed description may help to shine a light on the culture of restriction of noting and hiding NPT. This is being done through hiding the NPT behind other activities so that it is not being noted specifically in the report.

4.11 Unsolved problems

If several final well reports (FWR) from a variety of formations would have been analyzed a Monte Carlo simulation could be interesting to perform. This to predict the possibility, risk, and cost of lost circulation in different formations. Furthermore, it would have been interesting to see how downhole losses occurs in different formations if a significant amount of FWR would have been analyzed, and it would have been interesting to see if the results matches the results found in this analysis.

5 Conclusions

An analysis of final well reports and interviews with drilling professionals has been performed to understand downhole losses of drilling fluid related to drilled formations. Analysis to understand LCM used and NPT due to downhole losses has also been performed. The findings are summarized in the following:

- An approximately equal percentage distribution in downhole losses was reported between sandstone and limestone formation. Karstified formation was reported at 5%. Due to few numbers of final well reports, it is impossible to conclude whether one formation is more prone to downhole losses than others.
- The final well reports showed that the losses were larger in limestone formations than in sandstone formations.
- It was impossible to distinguish or find loss trends with the respect of wellbore inclination. This is due to lack of wells with downhole losses in deviated or horizontal sections.
- $CaCO_3$ and graphite is frequently used as LCM. In wells where severe downhole losses had occurred, 74% of the total product used are these two products in combination or alone.
- Results indicates that $CaCO_3$ and graphite used alone or in combination as LCM is insufficient.
- A standardized testing protocol would have been beneficial since todays API practice is insufficient to give any meaningful data on LCM performance.
- Apart from the cases where CML were used, the treatment did not differ between formation drilled even though it is different pore and fracture sizes in different formations.
- On average approximately 800m^3 of drilling mud were lost in wells where severe losses had occurred.
- On average 0.3 MNOK were spent on LCM in wells where severe losses had occurred.
- On average, slightly above 50 hours were lost due to lost circulation at wells where severe losses had occurred. This came at the average NPT cost of 14.5 MNOK, which is above 50 times the cost of LCM.
- A wider and a more remedial LCM approach might be considered since the cost of today’s LCM treatment roughly only equals one hour of NPT.
- CML was used in Karstified formations and in one case of sandstone formation.

When CML is not used, the cost distribution in wells where severe losses had occurred was as following: NPT cost 86%, mud lost cost 9%, diesel cost 3% and LCM product cost 2%.

- With CML present the cost distribution in wells where severe losses had occurred was as following: NPT cost 52%, CML cost 39%, mud lost cost 6%, diesel cost 2% and LCM product cost 1%.
- On average 2950 tons of CO_2 was discharged from wells where severe downhole losses had occurred, due to increased NPT.
- On average slightly above 200 tons of NO_x is discharged from wells where severe downhole losses had occurred, due to increased NPT.
- CO_2 and NO_x emissions in wells where severe losses had occurred was accountable for on average 2.6% of the well’s total emissions. In the well with highest emissions it was accountable for 5.8% of the well’s total emissions.
- Standardized LCM reporting and a standardized decision flow chart should be developed and become the preferred alternative. This in order to pass forward as much valuable information as possible, making it more likely to draw good conclusions. This will give a good basis for further development.

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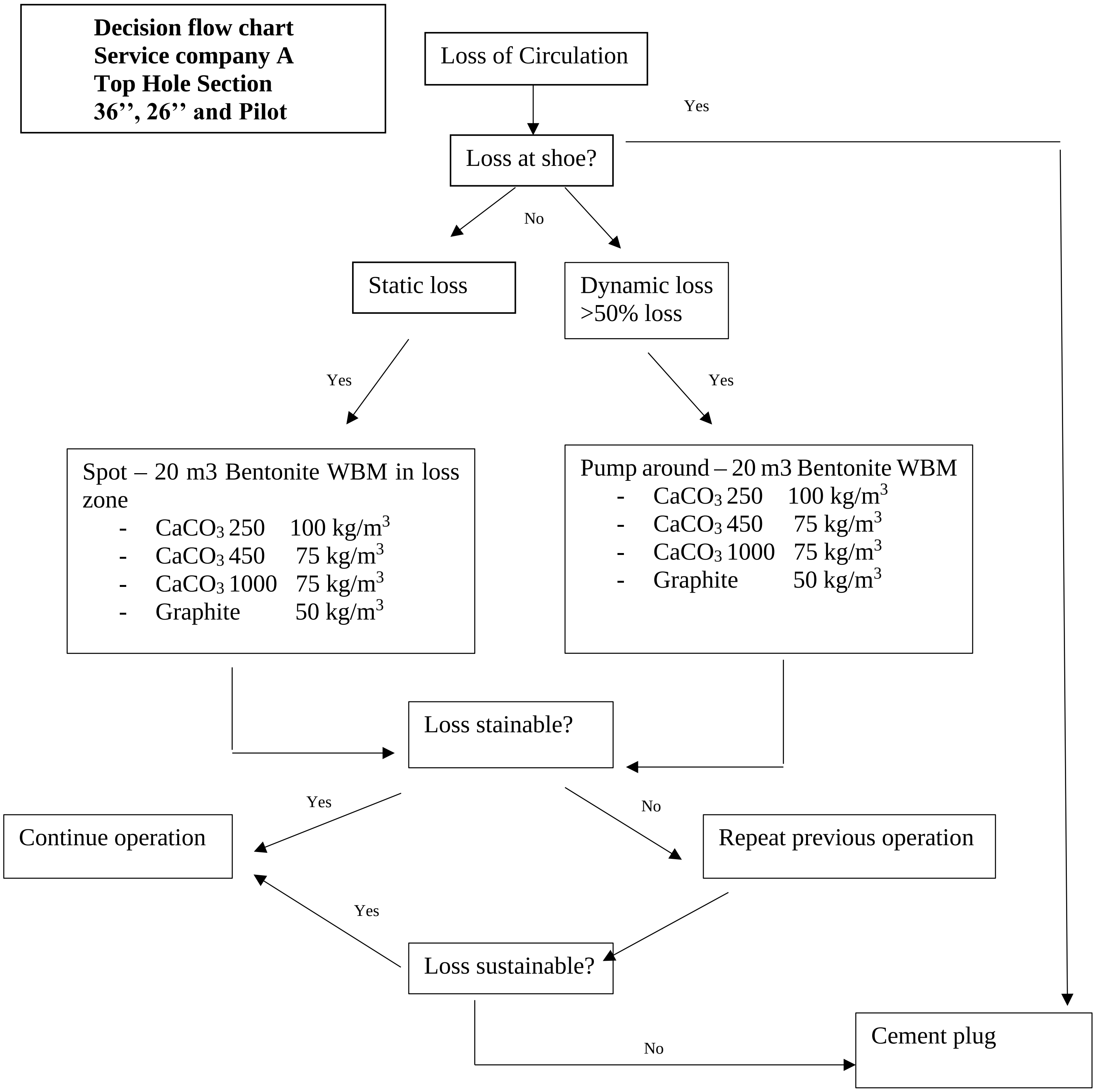
7 Appendix


Decision flow chart
Service company A
Top Hole Section
36’’, 26’’ and Pilot
Loss of Circulation
Yes
Loss at shoe?
No
Static loss
Dynamic loss
>50% loss
Yes
Yes
Spot – 20 m3 Bentonite WBM in loss zone
- CaCO3 250 100 kg/m3
- CaCO3 450 75 kg/m3
- CaCO3 1000 75 kg/m3
- Graphite 50 kg/m3
Pump around – 20 m3 Bentonite WBM
- CaCO3 250 100 kg/m3
- CaCO3 450 75 kg/m3
- CaCO3 1000 75 kg/m3
- Graphite 50 kg/m3
Loss stainable?
Yes
No
Continue operation
Repeat previous operation
Yes
Loss sustainable?
No
Cement plug

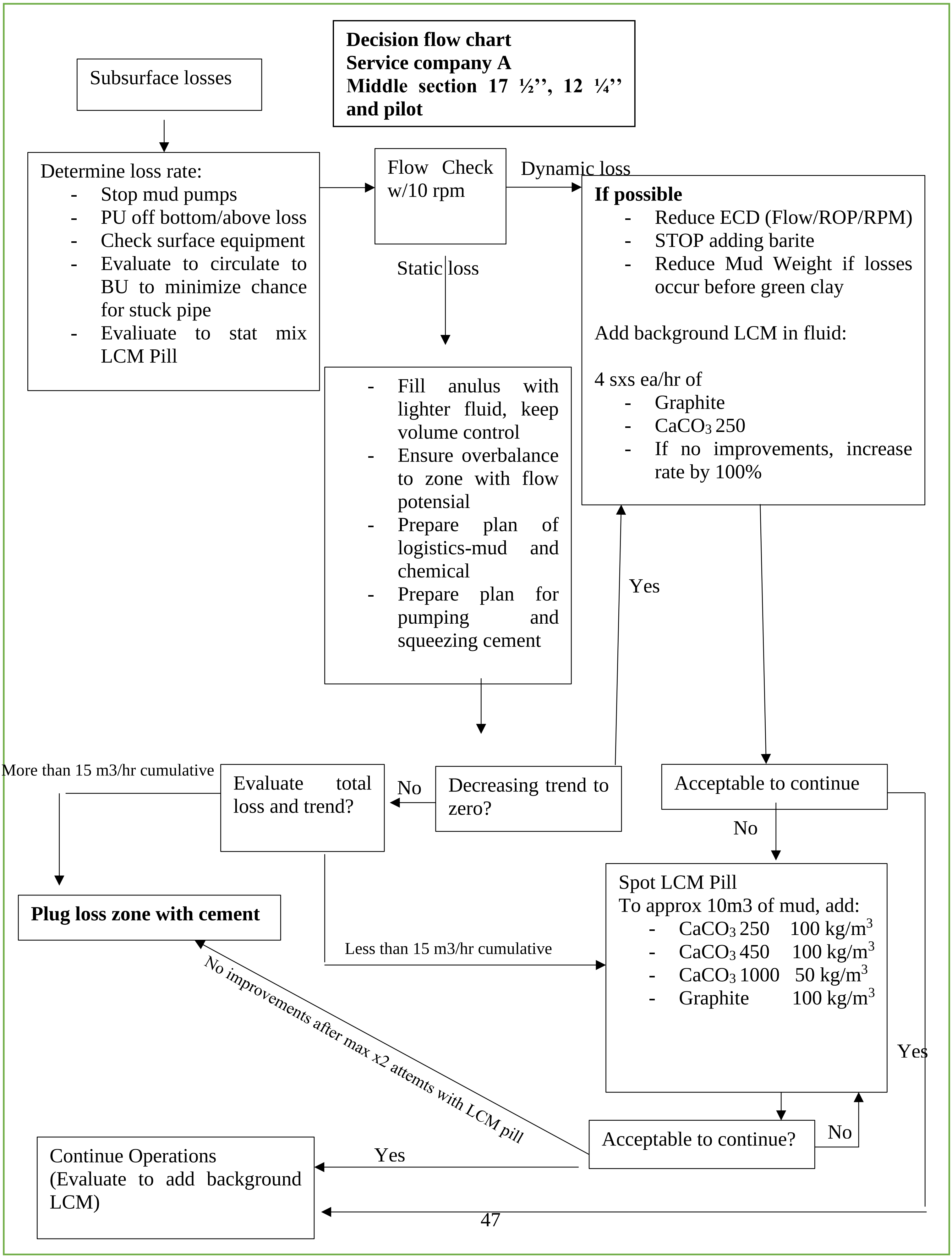


Figure 7-1 Decision tree Service company A. Middle hole section

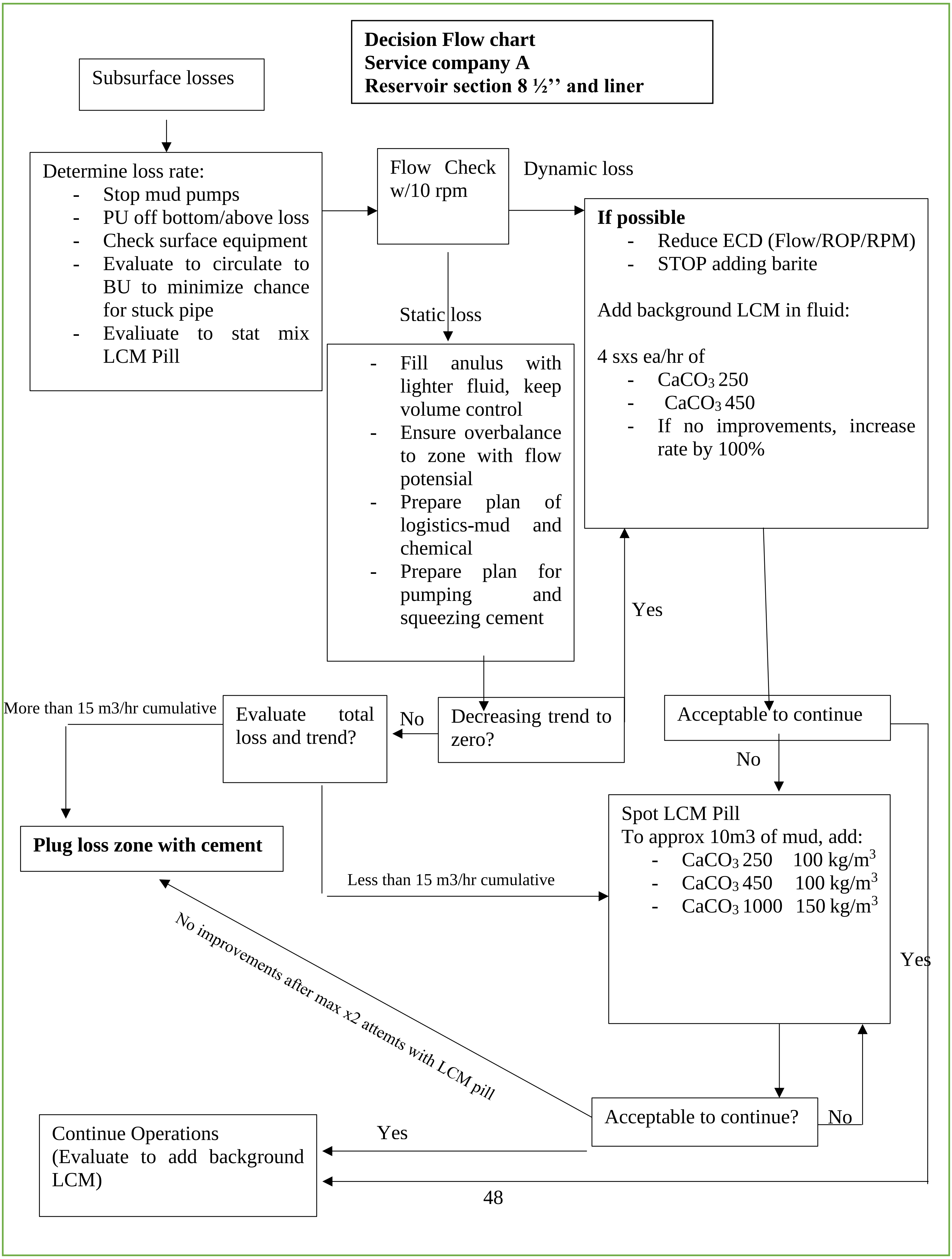


Figure 7-2 Decision tree service company A. Reservoir section.

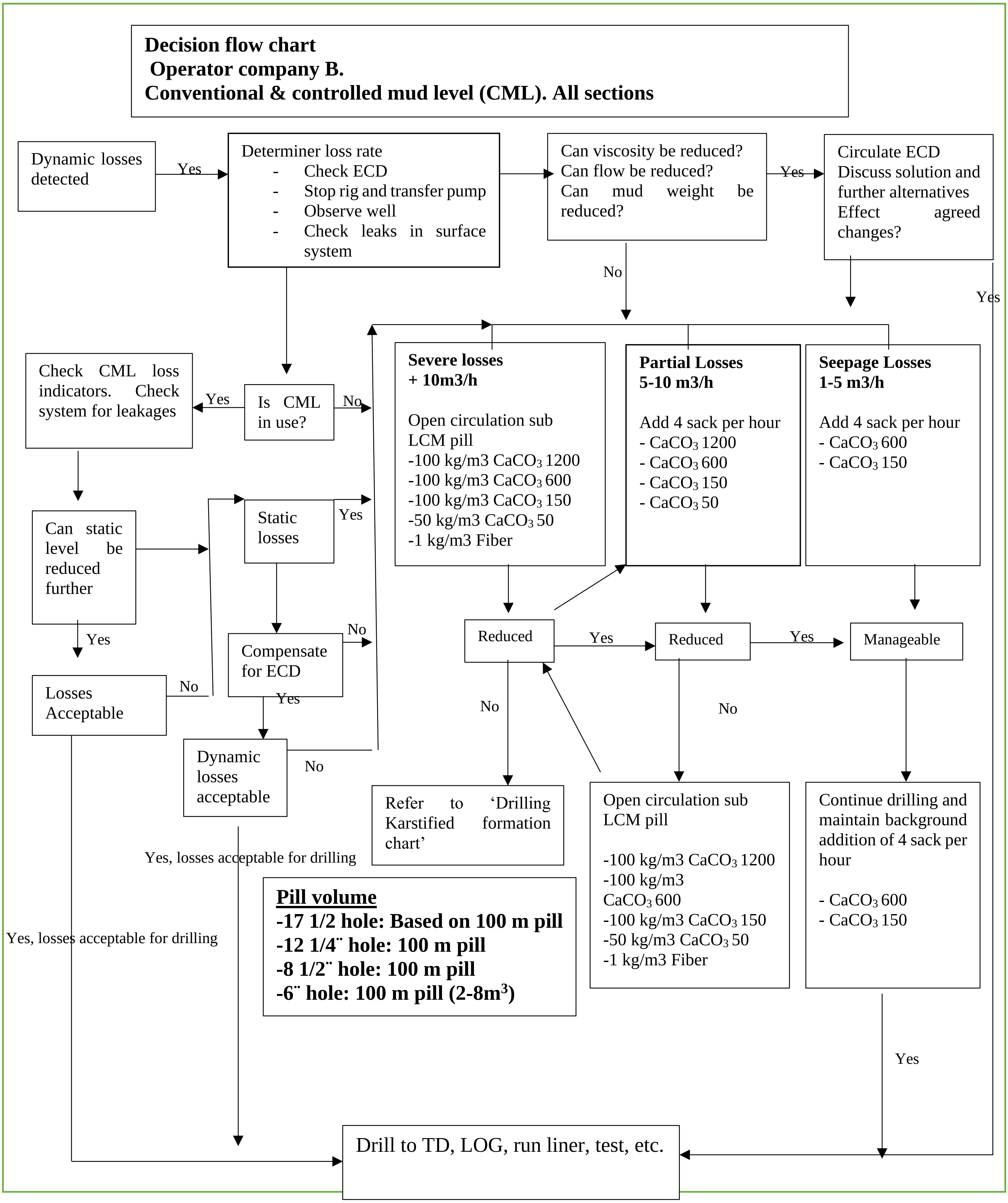


Figure 7-3 Decision tree Operator company B. All sections and with CML

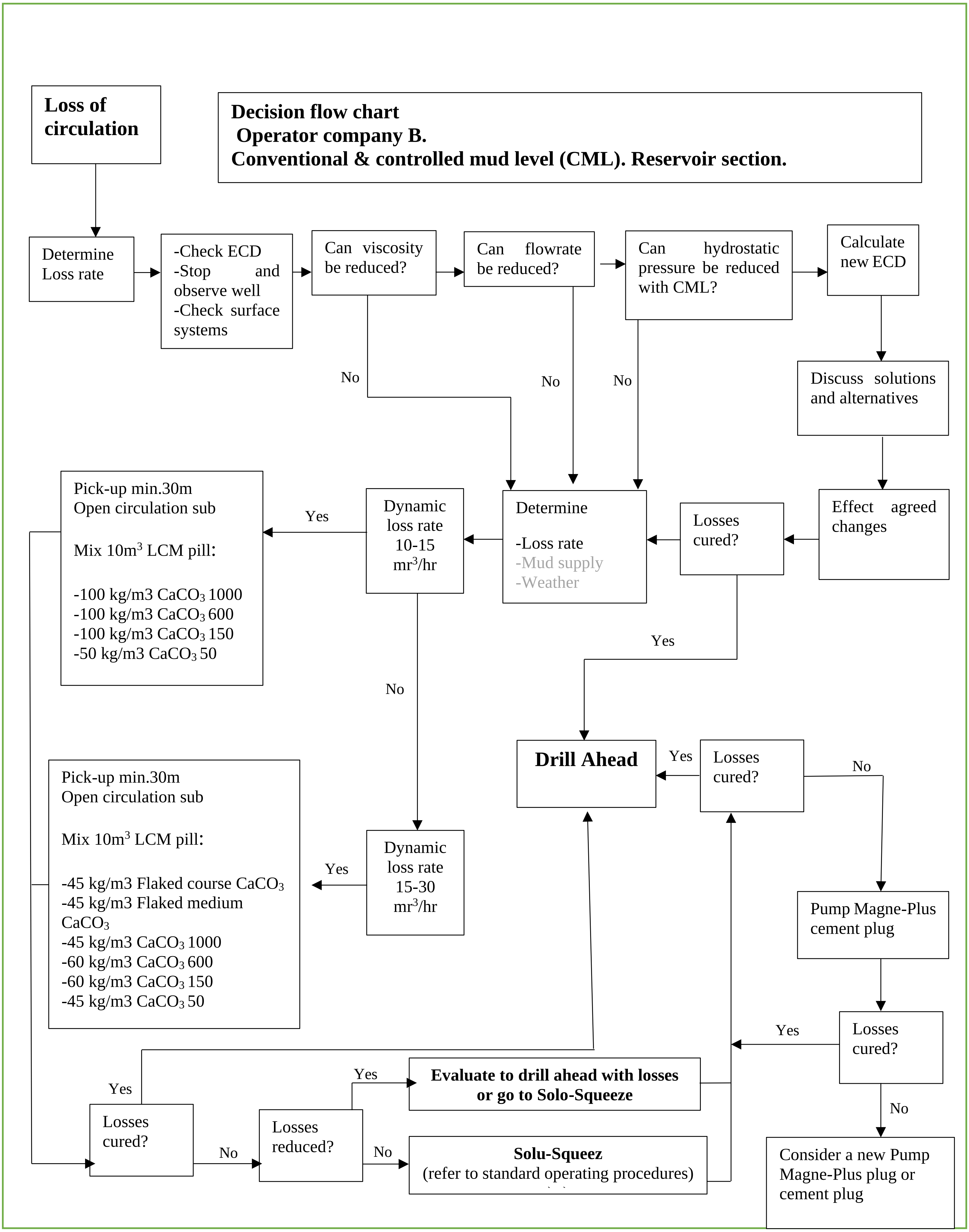


Figure 7-4 Decision flow chart. Operator company B. Reservoir section.

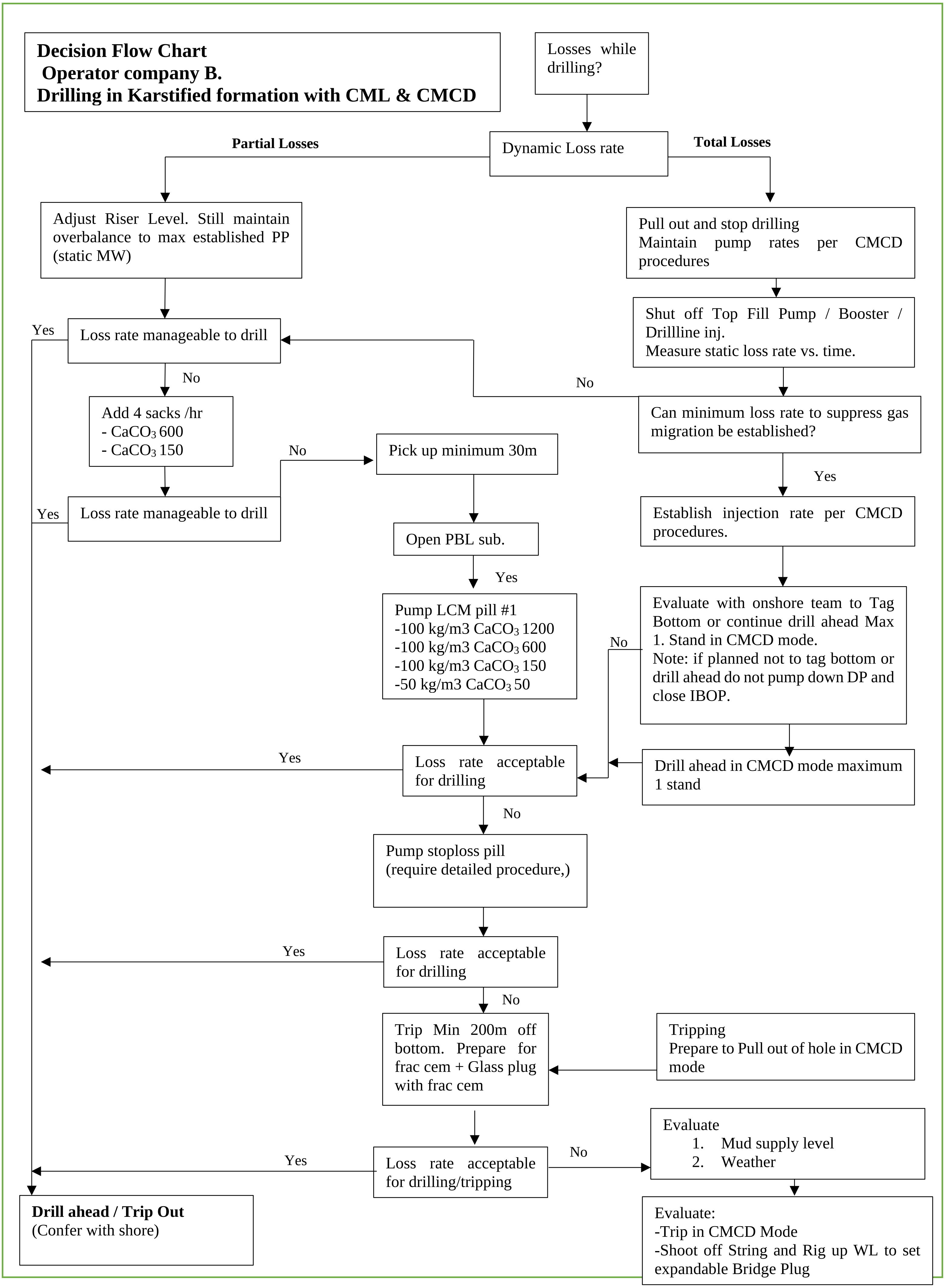
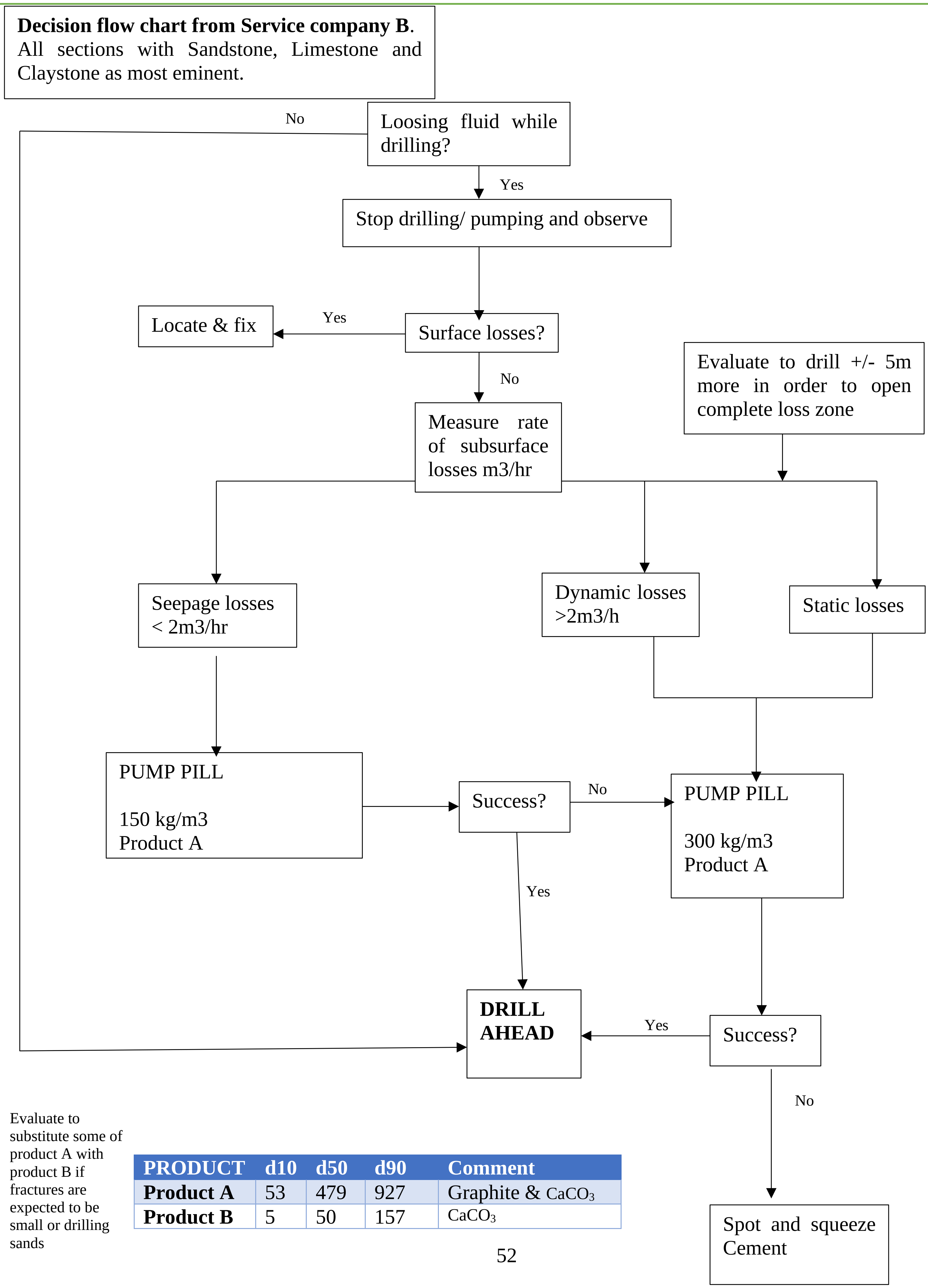


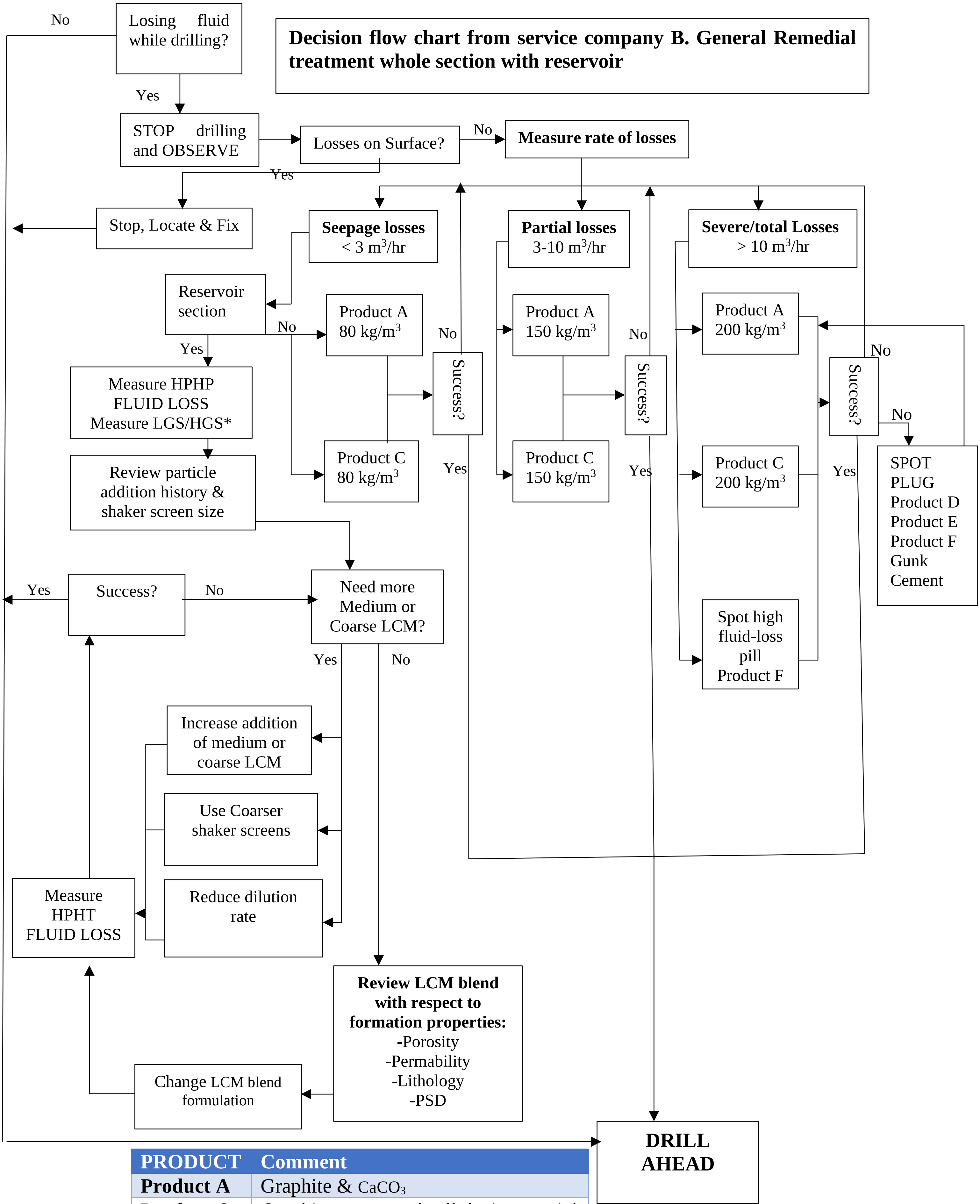
Figure 7-5 Decision flow chart operator Company B. Karstified formation



Evaluate to substitute some of product A with product B if fractures are expected to be small or drilling sands

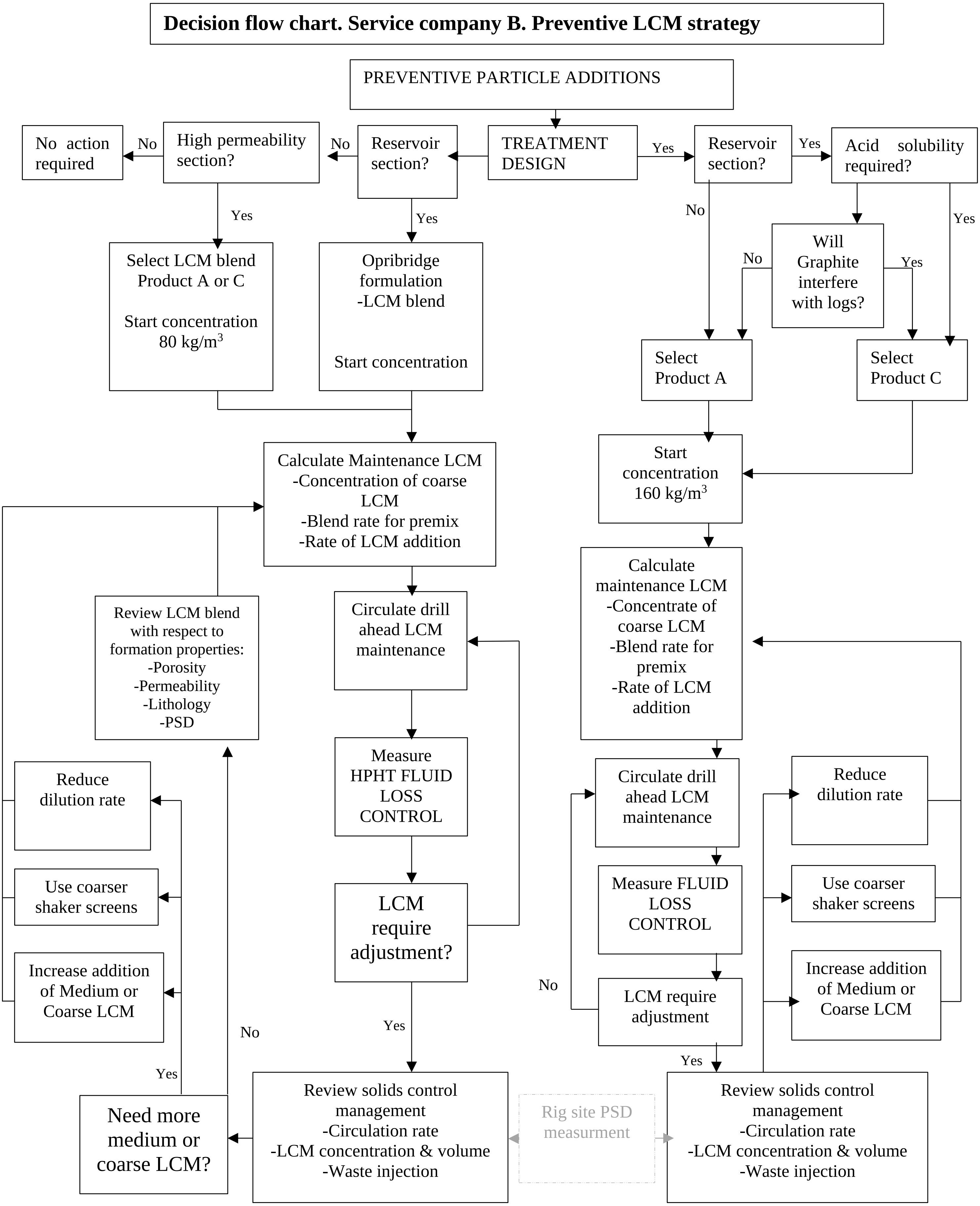
PRODUCT	d10	d50	d90	Comment
Product A	53	479	927	Graphite & $CaCO_3$
Product B	5	50	157	$CaCO_3$

Figure 7-6 Decision flow chart from service company B. All sections.



PRODUCT	Comment
Product A	Graphite & $CaCO_3$
Product C	Graphite, $CaCO_3$ and cellulosic material
Product D	Acid soluble lost circulation plug
Product E	Powder material to enhance thixotropy
Product F	High solids slurry

Figure 7-7 Decision flow chart from service company B. General Remedial treatment whole section with reservoir



PRODUCT	Comment
Product A	Graphite & $CaCO_3$
Product C	Graphite, $CaCO_3$ and cellulosic material

Figure 7-8 Decision flow chart. Service company B. Preventive LCM strategy