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UNDERBALANCED DRILLING TECHNOLOGY

TEHNOLOGIJA BUŠENJA U UVJETIMA PODTLAKA

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Abstract

Historically, most underbalanced drilling (UBD) projects were undertaken to eliminate drilling problems and cost. However, recently, the reduction of formation damage has become a main focus for underbalanced operations. This has the greatest potential in directly increasing the profit to the operating company. Potential benefits include increasing of production rate, the ultimate recovery, and enabling accelerated production. Underbalanced technology, while still on a sharp growth curve, is finally becoming accepted as a normal method for handling the drilling and completion of wells. This paper details the benefits and limiting factors of UBD technology, underbalanced fluid system selection, and UBD techniques, as well as candidate screening and selection.

Ključne riječi: bušenje u uvjetima podtlaka, zrak, dušik, magla, pjena, isplaka

Sažetak

Povijesno gledajući, tehnologija izrade kanal bušotine u uvjetima podtlaka primjenjivana je u praksi radi eliminiranja problema do kojih je dolazilo tijekom bušenja i radi smanjenja troškova. Posljednjih godina glavni cilj izrade kanal bušotine u uvjetima podtlaka postaje smanjenje oštećenja ležišnih stijena. Time se postiže najveće povećanje dobiti naftne kompanije. Potencijalne koristi obuhvaćaju povećanje proizvodnje, konačnog iscrpka i omogućavanje bržeg uključivanja bušotine u proizvodnju. Primjena tehnologija izrade kanal bušotine u uvjetima podtlaka i dalje je u porastu i konačno postaje prihvatljiva kao normalna metoda za izradu i opremanje bušotina. U radu se opisuju koristi i ograničenja u primjeni UBD tehnologije, izbor radnog fluida za bušenje u uvjetima podtlaka, metode UBD, provjera i izbor stijena pogodnih za primjenu ove tehnologije.

INTRODUCTION

Underbalanced drilling conditions occur when the effective downhole circulation pressure of fluid system in contact with rock formation is lower than the existing formation pressure. UBD has been utilized to minimize formation damage due to invasion of mud solids and fluid filtrate into permeable and fractured formations. However if the drilling fluid does not have the adequate invasion property, the severity of losses to the formation could increase if underbalanced conditions are not maintained at all times (Mc Lennan et al., 1997).

In some cases, UBD is the only technology available for drilling a formation. In most cases, this is due to the low pressure of the formation and the permeability of the formation. For formations whose fracture gradient is less than the lowest available fluid density, losses to the formation will occur. If the permeability of the formation will not allow drilled solids to penetrate the formation and losses are great enough to hamper good hole cleaning, the hole may be lost due to mechanical sticking. UBD is a technology that will allow access to the zone. Whatever the reason for applying underbalanced technology, the increased cost associated with applying the technology must be outweighed by the potential reduction in total cost or offset by an increase in production.

The number of underbalanced wells drilled each year increase as people see the advantages of applying the technology. It is estimated that ultimately 30% of all wells drilled will have some UBD component (Al-Ajmi, 2003).

New technologies developed in the late 1980s and through 1990s have seen a reemergence of UBD, with improvemets in multiphase modeling capabilities and the developmen of:

- higer pressure rotating control heads,
- active rotating control heads,
- four-phase separators,
- recycling foam systems,
- electromagnetic MWD systems,
- membrane nitrogen generation systems.

Elimination of the problems that have historically plagued UBD technology and the introduction of horizontal drilling in the 1980s caused a rapid growth in the number of underbalanced wells drilled worldwide. UBD has since proven to be an effective technology in minimizing the damage typically found in horizontal wells.

The economical and technical reasons for using underbalanced technology can be classified under four main categories. These include: reduction in formation damage, reduction in drilling cost, increase in reservoir data, and only available technology to access a formation.

UBD – BENEFITS AND LIMITING FACTORS

Drilling underbalanced offers several significant benefits over conventional drilling techniques. These include (Benion et al., 1996; Halliburton Energy Services, 1998; Mathes et al., 1999):

- reduced formation damage/increased productivity/ reduced stimulation requirements,
- improved formation evaluation/identification of fractures,
- minimized loss of circulation,
- elimination of differential sticking,
- increased penetration rate,
- increased bit life,
- reduction/elimination of expensive drilling fluid programs,
- improved safety and reduced environmental impact,
- early production.

Reduced Formation Damage/Increased Production/ Reduced Stimulation Requirements

Increased productivity from a reservoir is perhaps the most important advantage of UBD. During UBD, the invasion of contaminants (drilled solids and foreign fluids) into the formation is prevented if the drilling operation stays in an underbalanced state. If the drilling fluid causes no damage, as is usually the case with UBD, the probability of stimulation is reduced. By employing UBD techniques, fluid/solid invasion can be minimized, or in some cases eliminated, thereby reducing formation damage and maximizing well productivity (Bennion et al., 1994).

Improved Formation Evaluation/Identification of Fractures

Another significant advantage of UBD is that it allows continuous reservoir evaluation and characterization. While production characteristics, such as fluid type, flow rates, and pressures can be identified, reservoir parameters such as static pressures can also be estimated while drilling underbalanced. Further, formation fractures and the resulting flow/pressures may be identified during UBD. Underbalanced conditions allow formation pore flow into the wellbore under a negative pressure differential, and therefore allow detection at the surface that would otherwise be masked by an overbalanced state. A marked increase in flow rate from the well detects the presence of a formation.

Minimized Loss of Circulation

Lost circulation is defined as the partial or total loss of drilling fluids to the formation being penetrated. It occurs when natural or induced formation openings are large enough to allow mud to pass through, and when the pressure applied by the mud column exceeds formation pore pressure. The severity of these losses varies from minor seepage losses to a complete loss of the returns. These losses can occur in unconsolidated or highly permeable formations, in naturally fractured formations, in formations with induced fractures, or in cavernous formations. Due to the nature of conventional drilling fluids, loss of circulation is a constant risk particulary in severely depleted reservoirs with high permeability. As long as an underbalanced state is maintained, there is no loss in circulation. For this reason, severely depleted fields or under-pressured reservoirs can be drill underbalanced. However, loss of circulation may happen with UBD in special cases, such as water flows, due to the formation of mud rings and subsequent packing off of the formation.

Elimination of Differential Sticking

In conventional drilling operations differential sticking is always a concern. Differential sticking occurs because of the filter cake, which has other beneficial effects, but in this case can be harmful, and the differential pressure between the fluid in the annulus and the formation. With UBD, there is no hydrostatic pressure differential to the formation and no filter cake. As most multiphase fluids do not have solids that produce the filter cake, one will not be generated. In underbalanced operations differential pressure acts from the reservoir to the annulus. If designed properly, it is impossible to have positive differential pressure in underbalanced operations. It is impossible to get differentially stuck while drilling underbalanced.

Increased Rate of Penetration

Rate of pepetration (ROP) depends on many factors. Some of them are weight on the bit, rotary speed, jet impact, hydraulic horsepower, rock strength, and chip hold-down force. A major factor that affects the ROP is the hold-down force. When mud-column pressure is greater than the pore pressure in the rock, the overbalance holds the rock chip cut by the bit in the wellbore. In UBD with gasified mud, the pore pressure is greater than mud-column pressure. This lighter column allows the formation cuttings to flow up the system. The quick removal causes a large increase in ROP.

In UBD, there is no pressure on the rock to hold the solids in place and cause the deposition of the filter cake. Since the UBD fluid is free of solids, they cannot be reintroduced into the circulation system for re-grinding. Furthermore, since the formation pressure is greater than the wellbore pressure, less energy is expended in breaking the rock, and results in extraordinarily high rates of penetration. Increases of penetration by a factor of ten with respect to conventional drilling are not uncommon while drilling underbalanced as compared with conventional drilling.

Increased Bit Life

A considerable amount of heat is generated by friction at the bit, between the drill string and wellbore. Transportation of heat away from the bit is more efficient in underbalanced operations than in conventional drilling. Since there is no additional force holding the formation in place (less frictional force), the bit does less work to cut the formation. By using UBD, the fraction of retained solids is maintained at a minimum value, depending if a one-way process is used or a closed-loop system is employed. UBD also requires less weight on the bit to obtain optimum ROP. This requirement reduces the load on the cutters and bearings and increases bit life.

Reduction/Elimination of Expensive Drilling Fluid Programs

In UBD simple fluids (such as, KCl water or produced oil) are typically used, and costly drilling fluid programs can be eliminated for the hole section drilled in an underbalanced mode. Significant cost savings may be realized by not losing expensive drilling fluids to the formation.

Improved Saftey And Reduced Environmental Impact

A properly designed UBD system is less reliant on personnel recognizing an accidental event. The system is designed to safely handle a continuous formation fluid inflow. For this purpose special equipment and procedures are required.

UBD systems also give a continuous positive BHP reading throughout the drilling operation. UBD requires naturally occurring constituents, such as gas and water, when gas, mist, and gasified liquid drilling techniques are applied. In some cases a corrosion inhibitor is required. The corrosion inhibitor can either be added to the liquid phase, or coated on the drill-string or both. Drilling with foam requires the addition of surfactants and defoamers. The chemical concentration of the additives are very low (ppm) and normally of a non-toxic nature. The majority of surfactants used for foaming agents are biodegradable. As gas is the larger component, very little waste is generated as compared to conventional drilling fluids. Therefore disposal problems are minimized when considering volume and toxicity.

Limiting factors

Limiting factors that may impact a UBD program are:

- additional engineering and operational complexity,
- potential hole instabilities (such as sloughing shales),
- increased operational risks such as higher surface pressures and continually flowing well during drilling,
- new methods of cutting transportation and disposal,
- utilization of specialized equipment,
- potentially higher daily operational costs.

UNDERBALANCED FLUID SYSTEM SELECTION

In designing an underbalanced fluid system, information on th reservoir characteristic, hole geometry, availability, environment and offset history must be considered (Table 1) (Al-Ajmi, 2003).

Underbalanced fluid systems and underbalanced techniques classification are shown in the table 2. The fluid system for a particular project is selected according to:

- the desired bottom hole pressure (BHP),
- tolerance to water influx,
- ability to clean the well,
- ability to prevent downhole fires,
- the ability to carry produced fluids to the surface,
- cost and environmental consideration.

Table 1 Data that must be evaluated when selecting a fluid for UBD

Tablica 1. Podaci koje treba procjeniti pri odabiru radnog fluida za UBD

Topic	Parameters
Reservoir characteristics	- Formation type (such as sand, limestone, and clay) - Pore pressure - Temperature - Formation bearing fluid (such as water, oil and gas) and characteristics (such as composition, water gas, and PVT) - Geophysical/geomechanics information - Permeability and porosity - Compatibility between reservoir fluids
Well geometry	- Directional characteristics - Hole size - Proposed casing program
Environmental	- Disposal (cuttings, production fluids, and drilling fluids)
Offset history	- Mud logs - Production history - Well test data - Seismic and drilling reports

Table 2 Fluid systems and underbalanced drilling techniques classification

Tablica 2. Klasifikacija fluida i metoda bušenja u uvjetima podtlaka

Fluid System	**Mud Weight (kg/m^3)**	**Underbalanced Drilling Techniques**
Gas (Air, Nitrogen)	0-2,4	Gas (Air) Drilling
Mist	24-72	Mist Drilling
Foam (Stable Foam and Stiff Foam)	72-600	Foam Drilling (Stable Foam and Stiff Foam Drilling)
Gasified Mud (Aerated/Nitrified Mud)	540-899	Gasified Drilling (Aerated/Nitrified Drilling)
Liquid	827 and above	Liquid Drilling (Flowdrilling)

Gases for Air/Gas Drilling

Natural Gas. Natural gas is the best fluid for air/gas drilling. Natural gas eliminates corrosion, downhole fires when the hydrocarbon-producing zone is penetrated, and fire blowback up the blooey line. Unlike nitrogen, however, natural gas will almost invariably form a combustible mixture when released into the atmosphere. This inherently higher potential for surface fires requires a few changes in operating procedures from those used in air drilling. In almost all instances, natural gas drilling currently requires a gas-supply pipeline near the rig site. Lease or pipeline gas is usually available in large enough quantities to meet the requirements of a drilling operation.

Air. Air is the most common gas used in air/gas drilling. The availability of compressors and boosters designed for air drilling makes it more convenient than working from a gas line. If the air and the hole are dry, no fire problem exists. The use of dry air has been limited to vertical wellbores that are small in diameter with no sour gas, and with no downhole fires anticipated. The main limitations of dry air drilling consist of water inflow, downhole fires, and wellbore instability. The flow of water into a well being drilled with dry air can cause problems that are significant enough to exclude dry air drilling.

Nitrogen. Nitrogen is used for the same conditions suitable for air. It can be used as the drilling fluid or as a component of it. The major advantage over air is that mixtures of nitrogen and hydrocarbon gases are not flammable. This removes the potential for downhole fires. Nitrogen is desirable where mist is being used with produced acid gases, such as CO_2 or H_2S, when drilling through condensate zones before setting casing, and when re-entering oil-producing formations. Circulating nitrogen lifts cuttings and liquid inflows the same way that air does. The principal limitation on the use of nitrogen for drilling operations is its cost (Chitty, 1998).

The flow charts of drilling fluid selection for vertical and horizontal wells are shown in Figures 1 and 2.

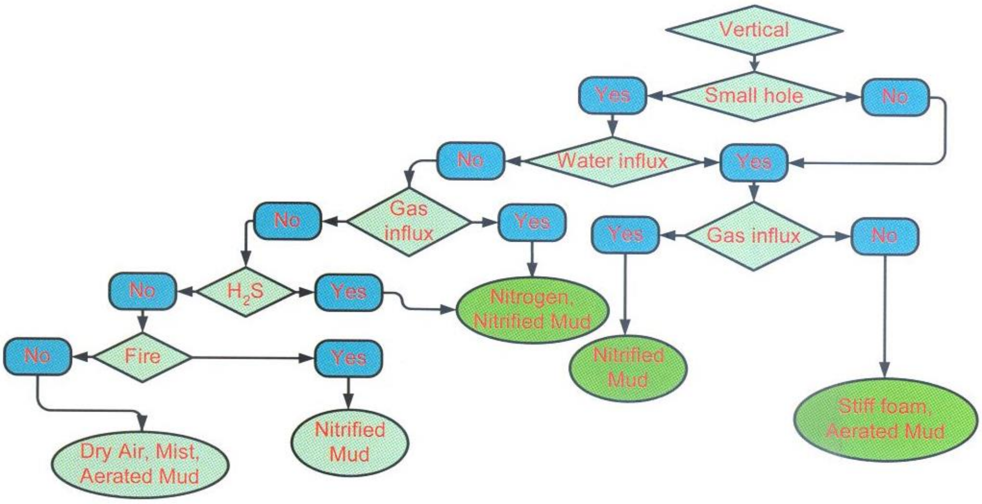


Figure 1 Flow chart of drilling fluid selection for vertical well

Slika 1. Dijagram toka za izbor fluida za vertikalnu bušotinu

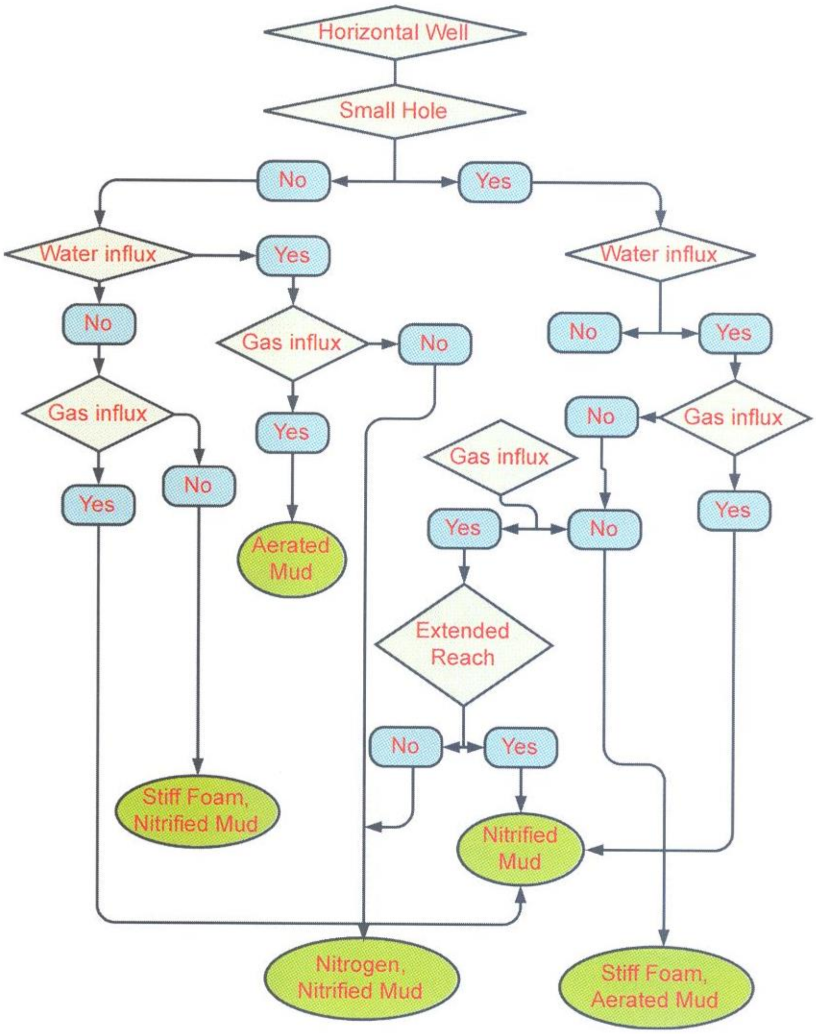


Figure 2 Flow chart of drilling fluid selection for horizontal well

Slika 2. Dijagram toka za izbor fluida za horizontalnu bušotinu

AIR/GAS DRILLING

Air or gas drilling uses air, nitrogen, or natural gas (preferably methane) as the gas phase in UBD. Drilling with air injection is common, but there are significant corrosion problems and the potential for downhole fires always exists. For these reasons, nitrogen has become the gas of choice for UBD. Figure 3 shows air (gas) drilling layout.

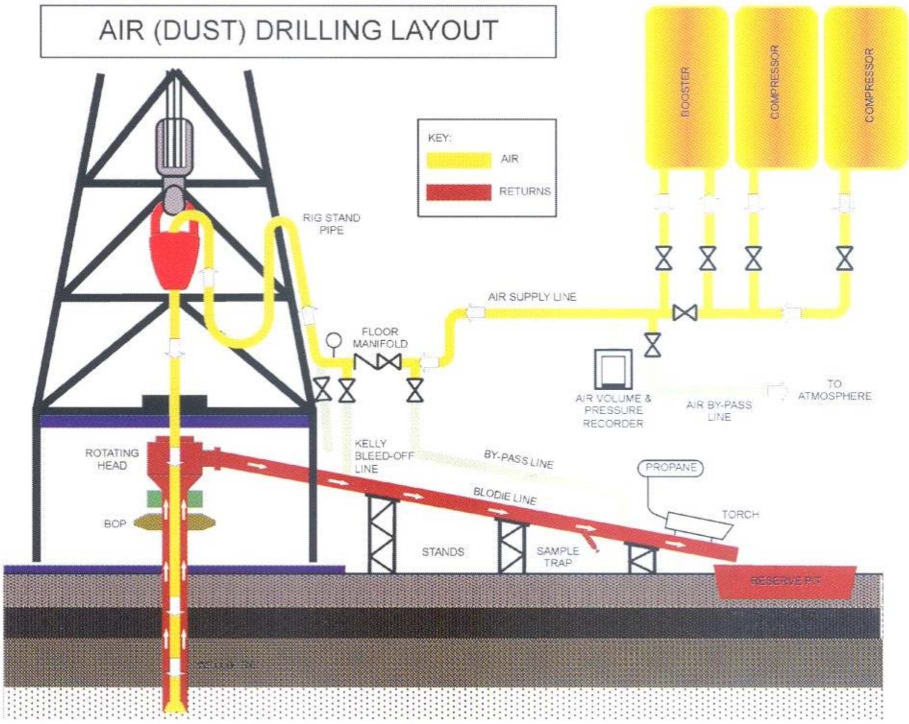


Figure 3 Air (gas) drilling layout

Slika 3. Raspored opreme kod bušenja uz primjenu zraka (plina)

The terms air drilling and gas drilling are often used because, from a drilling standpoint, their characteristics are virtually the same. Thus, little distinction is made between the two fluids; consequently, the term air/gas drilling is used to describe generally both air drilling and gas drilling.

Advantages to Air/Gas Drilling

Air/gas operations have advantages similar to several other UBD (Benion et al, 1995; Bennion, 1994). They include:

- increase ROP,
- reduction of time and cost involved in drilling a given section of hole,
- increased bit life with lighter bit weights,
- minimal formation damage,
- no productive zones hidden by extensive skin damage,
- on-line testing of production as it is encountered,
- better production from openhole completions,
- reduction of likelihood of lost returns in pressure-depleted and naturally fractured reservoirs.

Limitations of Air/Gas Drilling

Air/gas drilling has three main limitations: water inflows, wellbore instability, and downhole fires.

Water Inflows. The flow of water into a well being drilled is the primary limit to air/gas drilling. Water invasion causes the cuttings to ball up the bit and form mud rings on the wall of the hole. The balled bit stops drilling and mud rings limit hole cleaning. Methods available to shut off water inflow involve attempting to inject material into the water-producing formation, where it sets to form a barrier to water flow. The usual response to a water influx is to switch from dry air to mist or foam.

Downhole Fires. Spontaneous ignition of a light hydrocarbon fluid in an air atmosphere causes downhole fires. The possibility of downhole fires is a potential limitation on the use of dry-air drilling. Any time oxygen is introduced downhole in the presence of liquid hydrocarbons, the chance for a fire exists. If the mixture does reach ignition temperature, a downhole fire can occur. There are three steps in the development of a downhole fire:

- accumulation of cuttings in a region of low velocity: the top of drill collars or any regions of washouts in the annulus,
- formation of a mud ring; if a liquid influx is present in the hole, the cuttings can pack off around the drillstring and around the hole wall in regions of low velocity,
- formation of a small compression chamber in the wellbore annulus around the drillstring below the pack off.

As the air circulation continues in the annulus, the pressure in the chamber will rise. If liquid hydrocarbons are present, two of the three elements necessary for a fire are present: oxygen and fuel. The only element missing is a source of ignition. Another theory is that the compression of air in the temporary compression chamber can cause the temperature to reach the point necessary for combustion of certain hydrocarbons.

Wellbore Stability. Dry-air drilling usually leads to the lowest wellbore pressures of any drilling method. These low wellbore pressures can cause mechanically induced instability, especially in weak formations. Alternatively if there is a significant water inflow with water sensitive shales exposed uphole, it is possible for the produced water to cause wellbore instability as it is lifted out of the well. In a dry hole, broken or weak formations, such as coal beds, collapse and enlarge the annulus.

Corrosion. The oxygen level in water is a major factor in corrosion during air/gas drilling. Increasing hydrostatic pressure in the drilling fluid causes additional oxygen to be dissolved from a gas source, which makes a potentially more corrosive environment.

In distilled water at ambient temperature and pressure, the critical concentration of oxygen is 12 ppm. This would be the oxygen level in water that would cause the most corrosion. Since water is very common in well drilling and completion operations, a substitute (nitrogen) for oxygen may be more economical than using corrosion inhibitors.

Cutting Size. In air-gas drilling, the bit cuts chips, often 0,64 cm (¼ in.) long, plus some smaller fragments and dust. The larger chips can blow out of a shallow hole, but in deeper holes, the collars, drill pipe, and turbulence break up cuttings. The cuttings come out the blooey line increasingly smaller as the hole gets deeper, until eventually the cuttings become dust.

MIST DRILLING

Mist drilling refers to those operations where the drilling fluid is a combination of gas with a small ratio of water. Mist is formed if the liquid volume fraction is less than 2,5% water at the current pressure and temperature. For a mist system, the gas is the continuous fluid with liquid bubbles dispersed in the gas. To create a mist, a small quantity of water treated with a foaming agent is injected into the compressed air flow before it enters the drillstring. This liquid and any produced formation water are dispersed into a mist of independent droplets of liquid, which move at approximately the same velocity as the gas. In mist drilling, the volumes of liquid and gas injected into the well guarantee that the drilling fluid is a mist for at least part of its circulation trip. If an important water inflow is encountered, the liquid volume fraction downhole can increase to a level where foam is formed. Hydraulics in mist operations is mainly centered on cleaning the hole. Generally, a fluid that has gas as the continuous phase is the least efficient in terms of lifting cuttings. At any velocity, a fluid that has some viscosity will do a better job of lifting cuttings than a fluid having a lower viscosity. Consequently, extremely high velocities are common when mist fluids are the circulating medium. The minimum velocity of gas has to be greater than the slip velocity of the cuttings to bring them out and clean the hole. Figure 4 shows mist or foam drilling layout.

Limitations of Mist Drilling

Air Compression. Mist drilling normally requires air injection rates that are 30 to 40% higher than those required for dry-air drilling at the same depth and penetration rate. Similarly, standpipe pressures are 689,5 kPa (100 psi) higher. These increased air requirements lead to high daily fuel cost.

Waste Water Disposal. The water injected in the system will be circulated through the well every day. This water is not normally re-circulated, and disposal costs often exceeds 6 $/m^3. Additives injected into the well (corrosion inhibitor, polymers, etc.) also add cost.

Wellbore Instability. Mist drilling is unlikely to improve wellbore stability if mechanically-induced instability has been encountered in dry-air drilling. Wellbore pressure is normally higher when drilling with mist than with dry gas, but the difference is not very large in comparison with the in-situ stress. In mist drilling the gas flow rate tends to be higher and the density of the circulation fluid is greater than it is for dry-air drilling. These factors increase the potential for wellbore erosion if weak or poorly consolidated formations are penetrated. The aqueous phase in the mist-drilling fluid can cause chemically induced wellbore instability if water-sensitive shales are encountered. These shales tend to hydrate and swell, leading to undergauge hole, on exposure to certain circulating liquids during mist drilling. Swelling may be reduced by the addition of salts, such as potassium chloride (KCl), to the injected water.

Corrosion. There is a significant potential for rapid corrosion of downhole equipment during mist drilling. When air is compressed, the high oxygen concentration present in the aqueous phase promotes corrosion of exposed steel. The best protection against downhole corrosion is adding an appropriate inhibitor to the injected water or the foaming agent.

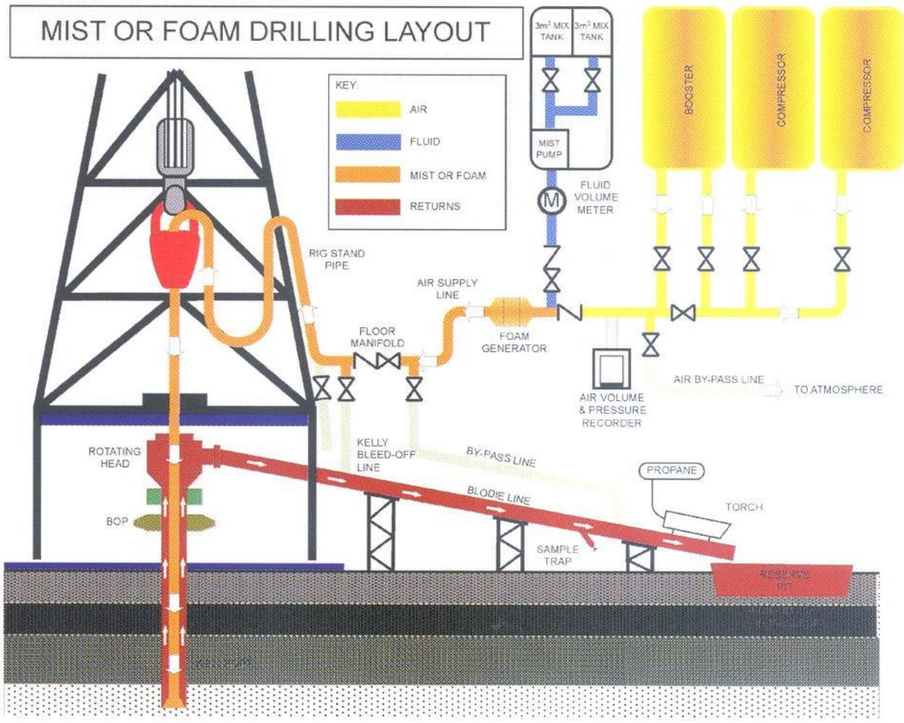


Figure 4 Mist or foam drilling layout

Slika 4. Raspored opreme kod bušenja uz primjenu magle ili pjene

FOAM DRILLING

Foam systems are created when water and gas are mixed with a surfactant. Foam is made of bubbles that are surrounded by a liquid film. A surfactant or foaming agent, in the liquid phase stabilizes the films that form the bubble walls, which allow the foam structure to persist. The structure of foam is made up of bubbles of gas surrounded by a liquid film. Foam normally contains about 97% gas and only about 3% liquid at surface conditions.

Two basic types of foam are used in UBD operations (Al-Ajmi, 2003; Hannegan, 2001 and 2002):

- stable foam, which uses only a surfactant as a binder, and
- stiff foam, which is built using not only surfactant but also bentonite and other polymers.

Foam can be generated using any gas. Air is most frequently used in foam drilling. Other gases, such as nitrogen, natural gas, or carbon dioxide, can be used instead. Acid gases such as hydrogen sulfide and carbon dioxide should be avoided since low-pH environments are detrimental to foam stability. Areas where hydrogen sulfide is likely to be encountered may exclude the use of foam as the underbalanced operating fluid. Almost any liquid can be used to generate foam. The most common choice is fresh water. Freshwater-based foam will be easier and cheaper to maintain. Since foamers are nothing more than soap, most are made specifically for use in fresh water. The only way freshwater will cause foam to deteriorate is when the foam quality is very low. Brine can also be used to generate foam, but specially prepared surfactants are required. Oil is seldom used as the base liquid for foam fluid. All liquid hydrocarbons are normally contaminants in foam systems and will cause extremely rapid deterioration of foam structure.The high effective viscosity of foam makes it an efficient medium for transporting cuttings. In fact, foam is capable of lifting very large cuttings. Any size cutting generated at the bit can be brought out of the hole with foam. Even when circulation stops, the foam will continue to expand for a while, lifting the cuttings (Murphy et al., 2002). In foam drilling, the efficiency of cuttings transport is in general at its lowest close to the top of the bottomhole assembly (BHA) because of low annular velocities. Since the effective viscosity of stiff foam is higher than that of unstiffened foam, it is possible to drill while having even lower annular velocities, and still maintain acceptable hole-cleaning efficiency.

This makes stiff foams suitable for drilling large-diameter holes, where the gas injection rates required for other lightened drilling fluids may not be economically feasible. This means that high-viscosity drilling fluids such as stiffened foams can become more attractive as the hole diameter increases. Stiffened foams are the preferred fluids for drilling holes with diameters of 0,4318 m (17 inches) and larger with anticipated water influx, but no significant gas influx. Stiff foams tend to be more stable than unstiffened foams. For this reason, they are more resistant to the gravity segregation that can lead to downhole combustion in long, horizontal sections. Stiff foams can give better wellbore stability through poorly consolidated formations than other lightened drilling fluids, including unstiffened foams. Gas inflows can pose a problem for stiffened foams. Since stiff foams tend to be used at higher qualities, there is more chance for the foam structure to collapse downhole in the presence of gas influx. As a consequence, the annular velocity of the collapsed foam will be too low for efficient cuttings transport. Under these circumstances, we take nitrified mud, or aerated mud as an alternative.

Quality of foam is the percentage of gas in the foam at a particular depth or pressure. Foam with a quality of 75% means it is 75 percent gas and 25 percent water. The same foam deeper in the hole might have a quality of only 60% because increased pressure compresses the gas. Therefore, foam quality varies with hole depth. As the quality of the foam (ratio of gas to liquid) increases, the carrying capacity of foam also increases (Mathes et al., 1999). Good foam has foam quality between 55% and 97%. This keeps the foam stable. If the foam quality exceeds about 97%, the fluid undergoes a phase change and becomes a two-phase fluid having gas as the continuous phase. This is called a mist. A general composition for foam is as follows (Hale et al., 1992):

- 2,85 kg/m^3 soda ash to soften the makeup water and raise the pH.
- 0,71 kg/m^3 caustic soda.
- 0.5% foaming agent (5 l/m^3).
- Foam extender, which is added as required.
- Corrosion inhibitor; the amount depends on concentration and type. Typically, about 3 l/m^3 is added.

Uses of Foam Drilling

Reduction of Lost Circulation. Foam systems are among the best underbalanced lost circulation fluids. As a light fluid, foam has a major advantage in avoiding lost circulation. In most cases foam reduces bottom hole pressure (BHP). Consequently, flow is from the formation to the wellbore. The unique part of the foam system is the small bubbles that enter the lost zone, slightly expand, and plug the zone. The zone is plugged without solid material, which is a big advantage

Avoiding Reservoir Damage. Drilling mud almost always damages the reservoir near the wellbore. The best performance is obtained when flow comes from the reservoir into the borehole and does not push filtercake solids and filtrate into the formation (Rehm, 2002). Good practice in reservoir protection is to set casing on top of or into the reservoir and then drill the reservoir UB with a clear, non-damaging fluid or noninvasive foam. Foam is especially good because it is stable and has limited pressure surges.

Avoiding Differential Sticking. Differential sticking occurs when the drillpipe or drill collars lie against the side of the hole and pressure in the hole is higher than pressure in the formation. If the pipe becomes stationary for any reason, it can become stuck. Drilling mud solutions to differential sticking include the use of oil mud. The best solution is not to allow differential sticking conditions to exist. If the well is drilled underbalanced, flow is from the formation into the wellbore and filter cake and filtrate do not exist. Foam contains few or no solids; thus, even with differential pressure, the pipe can not stick.

Increasing Drilling Rate. Generally, the drilling rate increases as hydrostatic pressure decreases. In UBD foams can provide faster overall penetration rates. Cuttings and fluid removal will be more efficient, allowing higher penetration rates. A major effect on drilling rate is cuttings removal, which is determined by hold-down force. In UBD, pore pressure is greater than mud-column pressure. The lighter mud column pressure allows the bit cuttings to explode under the bit, and the lifting characteristic of the foam quickly sweeps the bit cuttings away. With rapid chip removal, a large increase in drilling rate is obtained.

Cleaning Holes. Hole-cleaning problems are minimized because the foam system has superior cuttings entrapment and transport properties. Foam lifts the cuttings and carries them with very little slip. Consequently, foam can clean a hole with small liquid volumes and low annular velocities. The foam system not only removes cuttings from the wellbore more efficiently, but it also holds cuttings in suspension when circulation is stopped. The lifting capacity of foam is greatest when the foam starts to expand; therefore, a foam-drilled hole tends to stay clear of cuttings.

Limitations with Foam Drilling

Corrosion. Corrosion control is not an impossible limitation to foam drilling. Adding an effective corrosion inhibitor and oxygen scavengers to the injected liquid will, in many instances, slow corrosion of downhole equipment to an acceptably low level. Its function should not be affected by any formation fluid inflows that might occur. Corrosion problems with foam increase with increasing depth, principally because of the associated increases in temperature (Beyer et al., 1972).

Wellbore Instability. Wellbore erosion has been lessened by reducing wellbore boundary shear stress in naturally fractured formations, drilled overbalanced. This occurs because foams are efficient in cuttings transport at low annular velocities. High quality foams normally used in drilling have high viscosities at low shear rates. It is reasonable to think that foam should have a lower tendency to erode the borehole wall.

Mechanical Instability. When drilling with foam, borehole pressures tend to be higher than those encountered when drilling with dry gas or mist. The difference may or may not be sufficient to have a beneficial effect on wellbore stability. Using foam could increase the borehole pressure. This would decrease the difference between circumferential stress and borehole pressure, but still may not provide adequate support (Teichrob, 1997). This will help reduce mechanically-induced wellbore instability in weak rock.

Chemical Instability. Foam is often used when significant formation-water inflows are encountered. These inflows will alter the composition of the foam liquid phase and may promote interaction with water-sensitive shales, exposed farther uphole.

Downhole Fires. The potential for downhole fires when drilling with air foam should be considered when planning a well, particularly a horizontal well. The main reported instances of downhole fires when drilling with foam are in horizontal wells (Beyer et al., 1972). With the low annular velocities usually used in foam drilling, gravity-induced separation may occur in the horizontal section. It is supposed that the reported fires occurred when the foam separated, forming an air-continuous phase, which could support combustion on the top side of the hole.

Foam Disposal. The economic benefit of continuing to drill underbalanced with foam must be balanced against the cost of handling and disposing it. Because of environmental concerns in many areas, it is not acceptable to put large volumes of foam into a reserve pit or to pump it overboard. Consequently, several methods of defoaming systems have been developed. Even if the foam, water, and chemicals are not reused, these defoaming methods are termed recyclable foam systems.

GASIFIED (NITRIFIED or AERATED) FLUID OPERATIONS

Gasified (nitrified or aerated) fluid is any fluid in which gas and liquid phases have been intentionally mixed to decrease the density of the fluid. The introduction of gas into the system lightens the fluid column by replacing some of the mud with gas.

Gasified systems are unstable because nothing ties the gas and liquid together. The gas in this case is introduced into the fluid at the surface before it enters the drillpipe, or downhole into the liquid at the annulus. The most common gases used are air and nitrogen. Oil, condensate, water (fresh or salty), and drilling mud have been used as the liquid phase for a gasified system. In general, the fluid system remains well-mixed in the annulus so that the hole will be adequately cleaned. At the same time, the selected fluid system is easily separated into its constituent phases once the system reaches the surface. Figure 5 shows aerated fluid drilling layout.

Gasified fluids are optimized to clean the hole and maintain the BHP below the pore pressure and above the wellbore-stability pressure. Proper hole cleaning and pressure maintenance are key to any successful

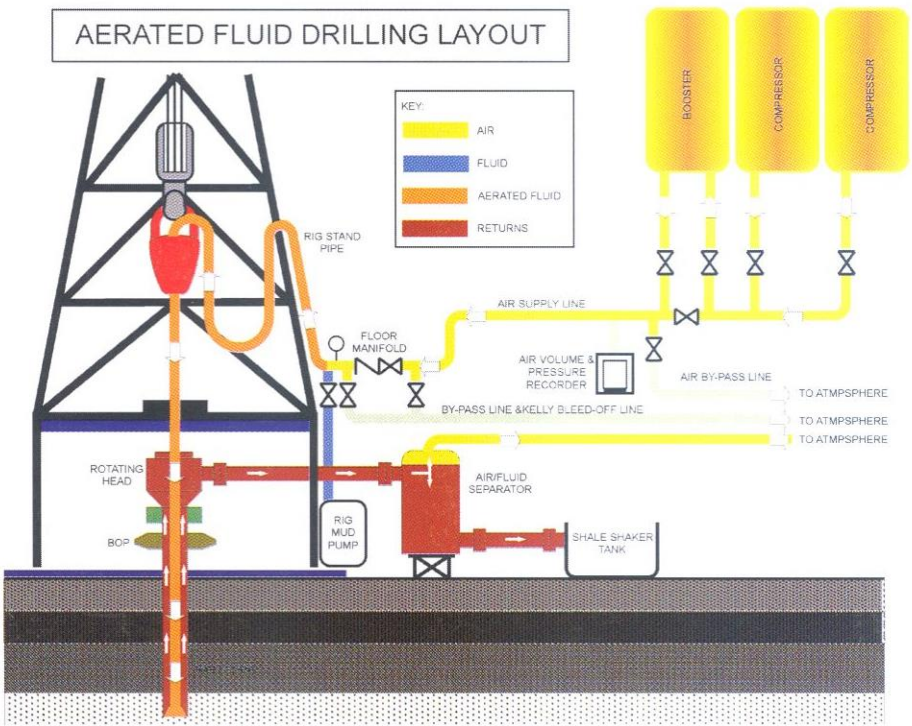


Figure 5 Aerated fluid drilling layout

Slika 5. Raspored opreme kod bušenja uz primjenu aeriziranog fluida underbalanced operation. To get the most benefit out of a gasified system, the best operating practice is to keep the entire fluid system tied together. Viscosities, gel strength, and velocity, among other forces, act in the annulus to maintain fluid stability with gasified fluids. This facilitates hole cleaning and avoids pressure-surge problems.

In UBD operations, the pressure will make the greatest impact on the gas properties. Because of the compressibility of the gas phase, the gas content of the fluid, as measured by volume, changes with temperature and pressure. Gas may be injected down the drillpipe, by parasite string, or by some other method.

The amount of gas in the fluid at any point, measured by volume, can be expressed as foam quality or as fluid ratio. Aerated and gasified fluids are commonly referred to in terms of ratio. Ratio is the ratio of gas to liquid unit under existing conditions of pressure. A good rule of thumb for a gasified fluid is to try to maintain the ratio through the system at 5:1 to 40:1 (i.e., 80 %< foam quality < 97.5 %) (Medley, 1998). The benefits of a gasified system are to avoid lost circulation, to reduce formation damage, to avoid differential sticking and, to increase the rate of penetration. Gasified systems prevent filter cake and filtrates from entering the formation.

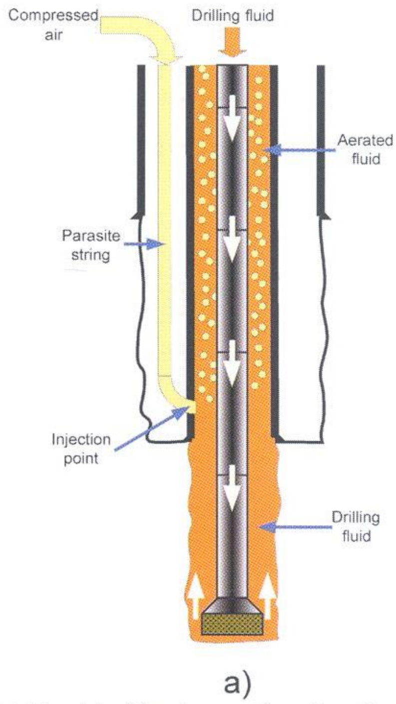
Limitations of Gasified Systems

The biggest problem with a gasified system is the discontinuous nature of the operations. Each time the normal operation is interrupted for some technical reason, the gasified fluid begins to separate, mainly in the annulus. Once the circulation is re-established, the resultant slugs of pure liquid can exert a hydrostatic pressure downhole in the formation that may exceed the reservoir pore pressure. Several techniques are used to mitigate the slug effect, mainly by creating gas slugs to counteract them. Bottom hole pressure (BHP) remains much more constant with gas circulation before connections. When circulation is restarted, the formation will initially feel the effects of only the gas-phase hydrostatic pressure.

The main problem with the use of gasified or aerated fluids has been handling the pressure and volume surges that are common while operating the system. Special equipment has been designed to carry a gasified fluid in the annulus or in a portion of the drillstring and part of the annulus, rather than circulating the gas phase all the way from the surface to total depth and back again (McGowen et al., 2000; Medley et al., 1998; Rehm, 2002).

Parasite Strings. A parasite string is simply a permanent or temporary tubular string connected or tied to one of the casing strings near the bottom (but above the float collar) in the wellbore that will allow for the introduction of gas into the annulus between the two (**Fig. 6 a**) (Rehm, 2002). Gas is injected into the tubing string at the surface and enters the mud system near the bottom of the surface pipe, normally at a depth of about 762 m at 914 m (2,500 at 3,000 ft).

Concentric String. A concentric string is defined as a casing string that is run into a wellbore and temporary hung off in a special wellhead, concentric to a permanent casing string (**Fig. 6b**) (Medley et al., 1998). Gas is injected into the annulus between the two strings.



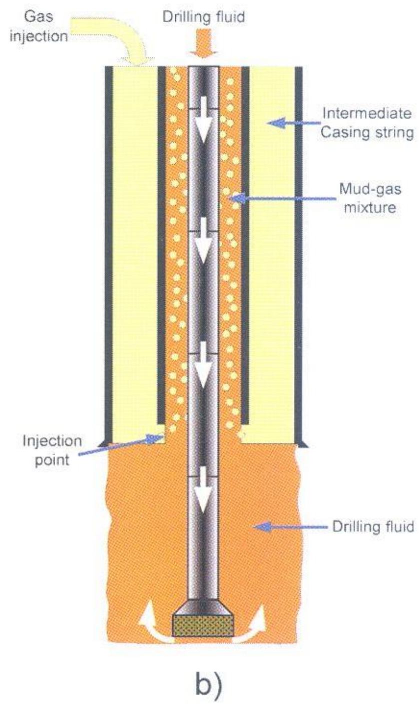


Figure 6 Parasite tubing string (a) and concentric casing string (b)

Slika 6. Parazitni niz tubinga (a) i koncentrični niz zaštitnih cijevi (b)

CANDIDATE SCREENING AND SELECTION

In general, at the current state of the technology, the reasons for the selection of UBD have been:

- Severe lost circulation or differential sticking problems while drilling conventionally.
- Highly depleted reservoirs, which typically present the problems (lost circulation, differential sticking) during conventional drilling.
- Hard rock formations that result in very low rates of penetration and poor bit life during conventional drilling.
- Formation damage resulting in wells with productivity below potential.
- Ability to evaluate formation productivity while drilling.

Certain wells or reservoirs are good candidates for underbalanced operations and result in an enhanced recovery. Other formations or fields may not be suited to underbalanced drilling for a variety of other reasons. A summary of indicators that help to determine whether

To a particular reservoir will be a good or bad candidate for UBD is listed in Table 3.

Table 3 Good and bad candidate indicators for UBD

Tablica 3. Pokazatelji dobrog i lošeg kandidata za UBD

Good Candidate Indicators for UBD	**Bad Candidate Indicators for UBD**
Depleted reservoirs. Typically exhibit lost circulation and differential sticking problems. If formation is consolidated, makes an excellent candidate.	Poor quality reservoirs. UBD can not make a formation something that it is not.
Naturally fractured and vugular formations. Usually exhibit huge losses, which can exacerbate well control problems or lead to differential or mechanical sticking, making them good candidates for UBD.	High pore pressure coupled with highly permeable formations. Are usually easily drilled overbalanced. UBD conditions are easily achieved, but the rates can be too high, leading to excessive drawdown, impractical surface equipment requirements, and associated problems.
Hard rock formations. Are usually consolidated and sustain UBD. Good candidates because of the improvement in ROP and bit life from UBD.	Shallow wells. Difficult to control bottomhole pressure and ensure continuous underbalanced conditions.
Highly permeable formations. Once again exhibiting lost circulation and/or differential sticking, making them good candidates.	Swelling shale and unstable formation. Wellbore stability problems if underbalanced.
Formation damage problems. Formation that usually suffer major formation damage during drilling or completion operations. Wells with a skin factor of 5 or higher is a good candidate.	Formation susceptible to spontaneous imbibitions. UBD can exacerbate formation damage.
Wells with massive heterogeneous or highly laminated formations that exhibit differing permeabilities, porosities or pore throats throughout.	Wells where drilling calls for frequent trips. Could create excessive oscillation between underbalanced and overbalanced conditions, causing damage, and eliminating the advantages of UBD.
High production reservoirs with low-medium permeability.	Candidates requiring UBD for long intervals. Although UBD can be achieved, the drawdown at the heel of the open hole intervals is likely to be very high when the bit is near the toe of a long interval, requiring impractical surface equipment requirements.
Formations with rock-fluid sensitivities.	Formations where knowledge of reservoir pressure is poor. Reservoir pressure drives the design of the UBD condition.
Formations with fluid-fluid sensitivities.	Wells with high H_2S. Producing fluids that contain high levels of H_2S will complicate the system design and may pose a safety risk.
Hole sections with variations of pressure.	The drilling of a section that contains formations with a wide variation in formation pressures may lead to cross flow or require impractical surface equipment requirements. Sometimes it may be feasible to reduce the wellbore sufficiently so that all zones produce into the well.

In screening wells for UBD, a controlling factor is the minimum drilling density at which the wellbore integrity is maintained (Medley et al., 1998). A stable rock is defined as a rock that can sustain a drilling fluid density less than the pore fluid density without collapse. Other wellbore and reservoir characteristics are also considered. These include (Figure 6):

- Assessing rock potential for formation damage such as clay swelling, fines migration, fluid/fluid incompatibility, rock/fluid incompatibility, phase trapping, bacterial damage, and chemical absorption.
- Evaluating rock potential for lost circulation.
- Assessing the well potential for stuck pipe.
- Assessing rock potential for hard drilling. Hard drilling conditions are experienced when drilling through dense formations with low permeability and low porosity. An increase in penetration rates of up to ten-fold has been reported in these formations when drilling underbalanced. The opinion about the likelihood of hard drilling is also provided by the user as a value between one and ten.

Once it has been determined that a particular well is a potential UBD candidate, the other wellbore and fluid specifics are considered. These include:

- the planned wellbore geometry, whether it is a vertical or horizontal trajectory,
- the planned diameter of the wellbore,
- evaluating the potential of penetrating water producing zones,
- assessing the potential for natural gas production,
- assessing the potential for sour gas production, and assessing the potential for downhole fire occurrence.

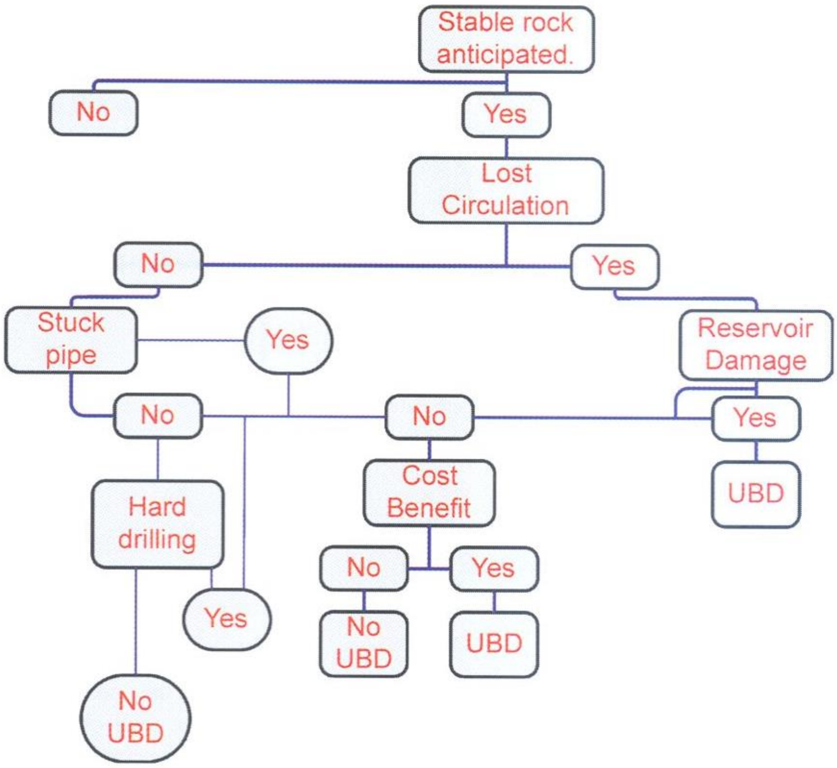


Figure 7 Flow chart for underbalanced drilling candidate selection

Slika 7. Dijagram toka za izbor kandidata za bušenje u uvjetima podtlaka

Once the candidate UBD technique is selected the UBD operation design system will go through three models to assure that the selected technique is the optimal selection in term of wellbore stability and economic incentives. These include (Figure 7):

- optimal circulation rate model (to assure an effective UBD operation)
- economic study model (to assure that the selected technique is an optimal
- selection in terms of economic benefits, and

- pressure calculation model (to assure that the selected technique is the optimal selection in term of wellbore stability).

UBD design system helps the engineer to achieve proper planning for UBD operation in order to achieve success for a particular well or project.

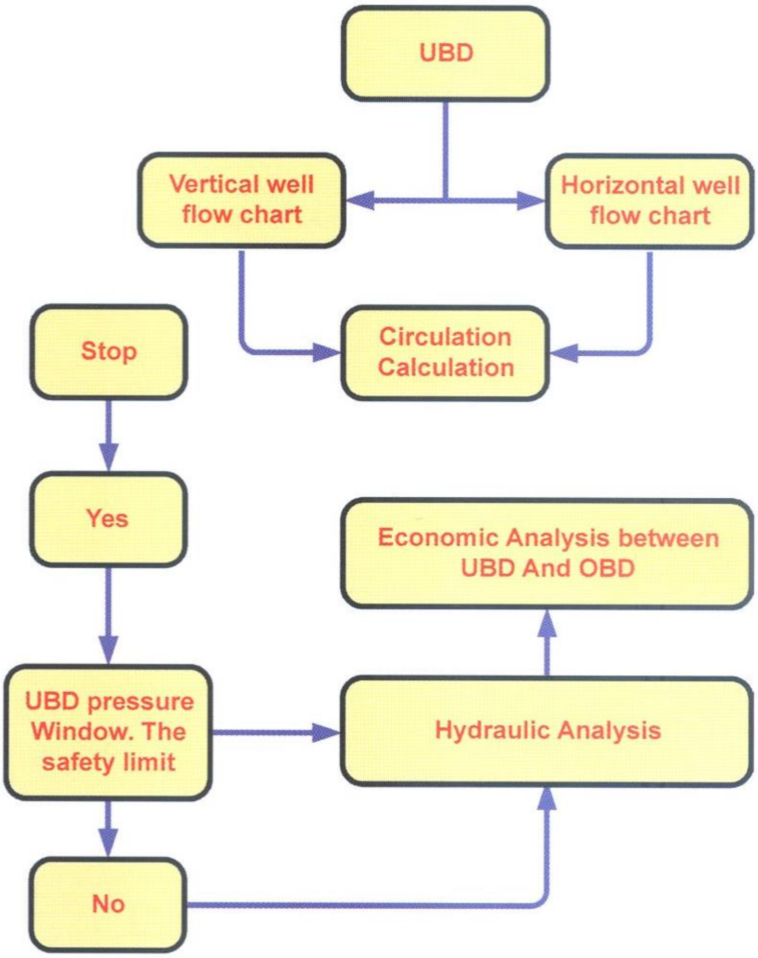


Figure 8 UBD operation design system flow chart

Slika 2. Dijagram toka za dizajn procesa bušenja u uvjetima podtlaka

CONCLUSION

Underbalanced drilling (UBD) has several advantages, and operators are slowly considering the use of UBD solely for its advantages, rather than merely as a solution to conventional drilling problems. UBD is not a technology that should be utilized for all situations. Utilizing the technology in the wrong application may create an unsafe situation, increase formation damage, increase the probability of well failure or increase well cost with no probability of economic gain. Before an underbalanced drilling operation is undertaken, a significant amount of work needs to be carried out by the reservoir engineers. Not only is an accurate reservoir pressure required but the damage mechanism of the reservoir must be understood to ensure that the required benefits are indeed possible.

The reason for applying a UBD technology is to increase profits for the company by increasing the production rate of the well or the value of the product produced or reducing the cost to drill the well. Improperly applying a new technology will increase the cost of the project, while not increasing the profitability of the project. This will lead to a loss of faith in the technology and ultimately a decrease in its use or eventual demise.

Notwithstanding these potential disadvantages, UBD may serve as an additional tool for an operating company to drill and produce from those reservoirs that cannot be exploited by conventional drilling methods.

The application of UBD permits total well management, both in terms of flow control and the measurement/evaluation of all returning fluids and solids throughout the drilling process. UBD has proven to be not only safe, but also cost effective and can result in an overall more efficient drilling program (depending upon specific well/field circumstances).

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