PLANNING & MONITORING OF UNDERBALANCED DRILLING TECHNOLOGY

A thesis submitted in partial fulfilment of the requirements for the Degree of Bachelor of Technology (Applied Petroleum Engineering)

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CERTIFICATE

This is to certify that two students of B.Tech (Applied Petroleum Engg.) – VIII Sem, Divay Kumar and Shivam Jaitley have completed the report of their major project, titled "Planning & Monitoring of Underbalanced Drilling Technology" under my guidance and have submitted the satisfactory report in this regard.

CK Jain. 03-05-08

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Last but not the least, we are thankful to all those students who helped us by participating in the discussions regarding the project.

ABSTRACT

Underbalanced drilling techniques have been applied to avoid or mitigate formation damage, reduce lost circulation risks, and increase the rate of penetration. However, drilling with a bottomhole pressure less than the formation pore pressure will usually increase the risk of borehole instability due to shear or tensile failure of the rock adjacent to the borehole. The extent of rock failure is very sensitive to the pressure in the annulus between the drill pipe, collars or BHA and the formation. The capacity of the drilling fluids to effectively circulate cuttings and cavings to surface is also strongly sensitive to the annular flow velocity.

This report describes the:

1. Planning of the UBD technology
2. Sub-surface & Surface Equipments used in UBD.
3. Fluid System involved in UBD technology
4. Completion in UBD technology
5. Monitoring of UBD technology

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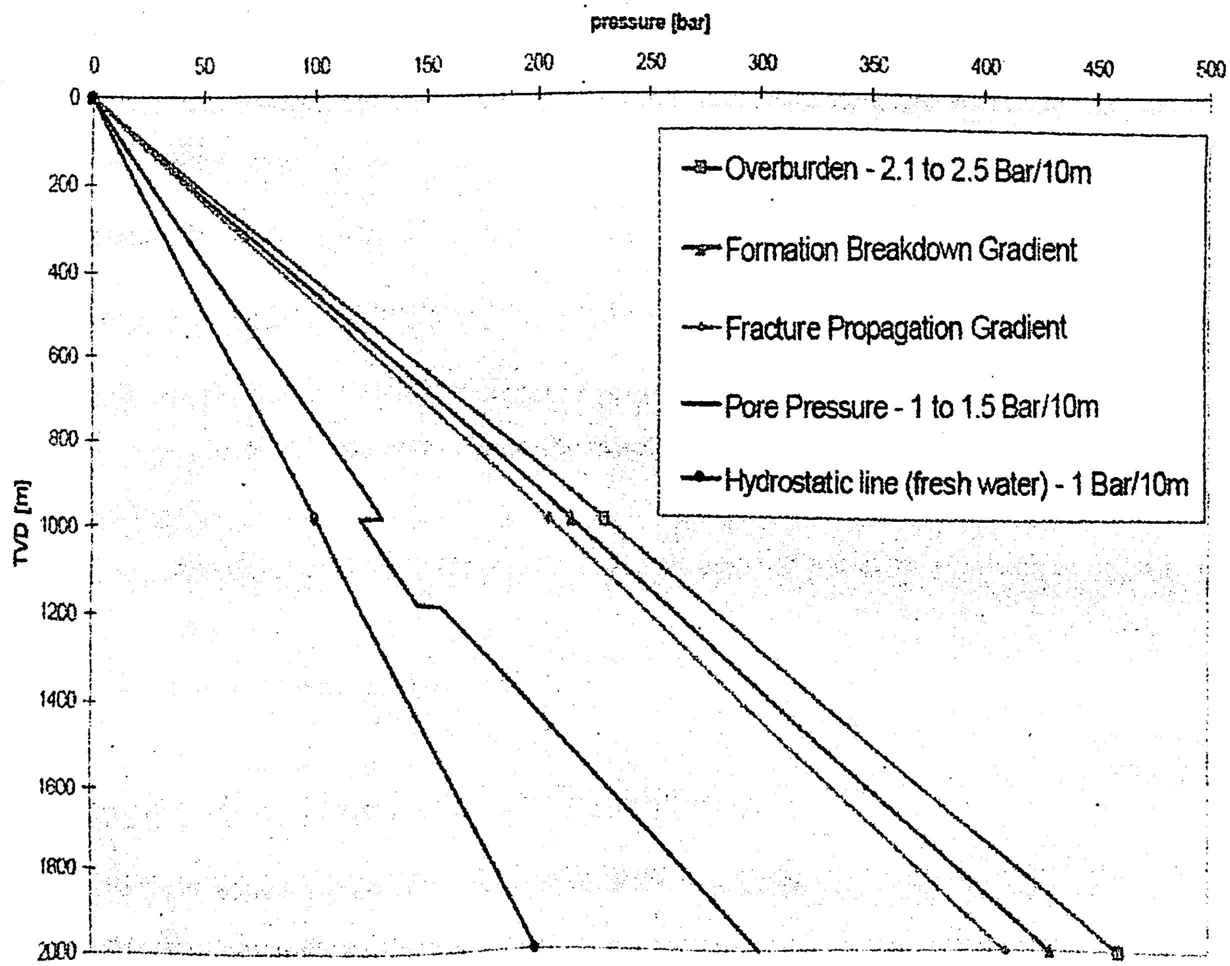
Chapter 1

1.0 Introduction to Underbalanced drilling

Underbalanced drilling (UBD), as opposed to conventional or overbalance drilling, is defined as a drilling operation in which circulating drilling fluid pressure is maintained to be lower than reservoir pore pressure. This method was developed in the late 1980s subsequent to extensive applications of horizontal drilling. By implementing this technique, the financial returns on drilling a well are improved because it reduces formation damage (especially in horizontal wells and depleted reservoirs), minimizes lost circulation (especially in fractured and depleted reservoirs), increases penetration rate of drilling, increases bit life, minimizes differential sticking, reduces stimulation, and improves formation evaluation. It is common practice that a horizontal section of the pay zone which creates a long exposure between the oil reservoir formation and the wellbore to be drilled horizontal to take advantage of the above benefits.
The underbalance condition is achieved by decreasing the effective downhole pressure or equivalent circulating density (ECD) of the drilling fluid. Since the downhole pressure includes the pressure exerted by the hydrostatic weight of the fluid column, the backpressure, and the frictional pressure drop in the annulus, the required reduction in drilling fluid pressure is performed by decreasing the density of the drilling fluid. For this purpose, depending on the reservoir formation and pore pressure, different drilling fluids such as dry air, nitrogen, natural gas, mist, stable foam, stiff foam, gasified liquids (aerated muds), glass bubbles, and liquids are utilized. In gasified liquids (aerated muds), a gas is injected into the liquid to reduce the density of the resulting drilling fluid. Since in these fluids the pressure difference between the reservoir formation and the wellbore is relatively low, fewer UBD related problems such as wellbore instability and formation fluid inflows are encountered. Various combinations of liquids and gases can be employed in gasified liquids. Water as the base liquid is the most common liquid for gasified liquids, especially produced water because it is readily available, compatible with the formation, and inexpensive. In some water-wet formations it may be

advantageous to use an oil-based drilling fluid since a water-wet formation could imbibe water even against a pressure gradient. On the other hand, the unique performance of oils makes them to be preferred to water as the liquid phase. Oils prevent clay swelling and they are resistant to contaminants.

Drilling Underbalanced into formations means to maintain a lower annular borehole pressure than the resident (formation) pore pressure. Depending on the porepressure this can mean everything from using water based mud with little weight material down to pure nitrogen as a Drilling fluid.



Pressure vs. Depth
Fig: 1.1

In the above picture it is graphically expressed that where in normal (slightly overbalanced) drilling we want to stay in between of the black line (Pore Pressure) and the purple line (Fracture Propagation Gradient), in UBD we deliberately go below the pore pressure during drilling. The main technical problem during UBD is to be underbalanced, without going so far underbalanced that the oil or gas flow from the reservoir will completely deplete the near wellbore zone. If this happens the well will become overbalanced and the near borehole formation will still be damaged. From a practical standpoint, this is the art of underbalanced drilling. As a reminder, drilling underbalanced is not always about compressible fluids. Plain water as a drilling fluid usually takes you to UBD also.

1.1 Advantages & Disadvantages of Underbalanced Drilling Technology

Advantages

Reduce Formation Damage (Negligible Fluid Invasion)

- Improve the productivity index (oil rate / press. drawdown [stb/d/psi]) of many wells
- Improve production rates and reduce the number of development wells required to deplete the pool
- Increase ultimate recoverable reserves by decreasing the pressure at which economical production ceases
- Minimal to no mechanical skin

Continuous, Real-Time Reservoir Investigation

- Identify tight zones, pinch-outs, discontinuities, fractures
- Measure flow capacity of the well
- Assessment of well productivity while drilling
- Assessment of bottom hole flowing pressure while drilling
- Estimates of OIIP and GIIP during drilling

• Optimize horizontal well bore length

• improve number and location of future development wells

Eliminate Lost Circulation Zones

• drill low pressure, high permeability or fractured reservoirs with no drilling fluid loss

• decrease drilling fluid costs by eliminating the need for fluid loss additives (LCM)

• reduce/eliminate production of previously lost drilling fluids

Eliminate Problems Associated with Differential Sticking

• Increase Penetration Rates

• reduce chip hold down

• decrease pressure against the rock being drilled allowing it to fail more easily

Reduce/Eliminate Expensive, Complex Horizontal Completions/Stimulations

Disadvantages

Increased Operational Complexity

• Space requirements for additional equipment

• Requires dedicated, knowledgeable personnel capable of providing onsite coordination of all services

• Rig crews may be unfamiliar with underbalanced drilling procedures

Conventional Mud Pulse MWD is Ineffective when compressible fluids are used

• The alternative electromagnetic MWD data transfer is generally more expensive and tool availability may be limited

• Wireline wet-connect steering tool result in slower connections and increased operational complexity

Poorly Managed Multiphase Flow Regimes can Create Drilling Problems

- Insufficient cuttings removal from the wellbore
- Motor can over-speed
- Excessive downhole motor stalling due to low effective fluid injection rates
- Incorrect fluid mix can create instationary drilling conditions and destructive vibrations

Increased Daily Costs Due to Additional Equipment and Personnel

1.2 Suitable Formations for Underbalanced Drilling Technology

Highly Competent

The hole must not cave into the wellbore during underbalanced operations. Typically, unconsolidated sands or sloughing shales requiring completion liners are not suitablecandidates. However, a number of underbalanced drilling operations have been successfully conducted in unconsolidated sands. Additional care may be required to prevent possible wellbore collapse. Rock mechanical analyses using appropriate models that account for transient pore pressure gradients in the near wellbore region can be used to assess underbalanced drilling suitability. Please contact us if you would like a reference to experts in this field.

Underpressured/Depleted Reservoirs or Pools

Underpressured or depleted zones are good candidates for underbalanced drilling since static reservoir pressure is less than the equivalent circulating pressure that can be attained with a single phase incompressible drilling fluid. Without the alternative of underbalanced drilling many zones would not have been drilled because of the possibility of lost circulation and stuck pipe that can be a concern when drilling conventionally.

Formations Sensitive to Rock-Fluid or Fluid- Fluid Interactions

Where permeability is reduced due to an interaction between the drilling mud and the reservoir rock or the drilling mud and the reservoir fluids, invasion of incompatible drilling filtrates into the formation can cause adverse reactions (e.g., clay swelling, wax and asphaltene precipitation) with the formation fluids. Underbalanced drilling can be used to avoid introducing potentially reactive fluids into reservoirs sensitive to fluid invasion.

High Strength Formations, Hard Rock Drilling

The absolute reduction in hydrostatic head and the differential between pore pressure and hydrostatic head both contribute to a substantial improvement in ROP over conventional mud drilling. In hard rock formations ROP can be up to 10 times higher. This reduces drilling time and associated costs and can be a pervasive reason to drill underbalanced.

Formations with High Permeability and Where Consolidated Sands Exist

In some cases the damage caused by conventional drilling may extend further into the formation than stimulation treatments can correct. It is difficult to design effective overbalanced fluid systems for reservoirs of this type because it is difficult to generate uniform, stable filter cakes to prevent mud filtrate and solids invasion.

Formations with Low Initial and High Irreducible Water Saturation

Due to fluid invasion, conventional drilling can increase the water saturation near the wellbore subsequently reducing the ability to produce hydrocarbons. Underbalanced drilling minimizes the direct displacement and entrapment of drilling fluids into the formation thereby maximizing hydrocarbon production.

Formations of Highly Variable Quality

Some formations exhibit wide variations in reservoir characteristics, such as permeability, porosity or pore throat size distribution. Overbalanced systems are conducted to protect the better quality sections of a producing zone while damaging the portions that can be potentially productive. Underbalanced drilling can result in more uniform production from the target interval.

Horizontal Wells

Filtrate invasion is a concern in horizontal wells where the reservoir is exposed todamaging drilling fluids for a longer period of time. Underbalanced drilling can keep formation impairment to a minimum because drilling fluids are not forced by hydrostatic pressure into the target formation.

1.3 Popular Misconceptions on UBD

Various misconceptions about underbalanced drilling have developed as industry tries to understand this emerging technology. Industry members have tried to relate underbalanced operations to their knowledge of conventional drilling methods and procedures. However, underbalanced drilling is a technically complex operation and these common misconceptions must be corrected.

1. Surface hydrocarbon production confirms that the well is being drilled in an underbalanced state.

Production of hydrocarbon only confirms that the well is underbalanced at some point along the openhole section of the wellbore. Many people assume that production of hydrocarbons during drilling confirms that the well is being drilled in an underbalanced state. Unfortunately, this may not be the case and is a dangerously simplified assumption. Large pressure drops, combined with localized reservoir inflow, may exist along the horizontal section resulting in underbalanced conditions near the casing and overbalanced conditions at the bit defeating the purpose of underbalanced drilling. Only highly trained and skilled personnel teamed with rigorous multiphase flow modeling software can determine if underbalanced conditions remain constant across the entire open hole section.

2. Air drilling principles apply to multiphase flow drilling technology

Application of multiphase flow principles differs from air drilling technology if the continuous phase in the multiphase system is liquid. In a system where gas is the continuous phase all lifting is done by gas and in that case all air drilling principles apply. Nevertheless the application of air drilling principles to multiphase underbalanced drilling projects can be catastrophic. Attempts to improve hole cleaning by decreasing liquid injection rates while simultaneously increasing gas injection rates may cause severe hole cleaning problems. Insufficient liquid in the multiphase flow stream provides very little energy for drilled cuttings transport. Enough liquid is often present however to do nothing more than wet the cuttings and create a paste-like consistency that leads to eventual pack offs and stuck pipe. Increasing liquid injection rates to clean a well while maintaining an underbalanced state is counter intuitive to most individuals with air drilling experience. As well, increased gas injection may actually increase bottom hole pressure due to additional frictional losses. A rigorous multiphase flow simulator must be used in order to evaluate all injection blend changes.

3. Flow Drilling and Underbalanced Drilling are the same

Flow drilling is the manipulation of drilling choke at surface to restrict reservoir inflow. Consequently, annular pressure at the point of inflow is essentially the same as the reservoir pressure. Flow drilling does not require detailed engineering analysis to increase the likelihood of success. Bottomhole pressure and hole cleaning are not monitored and differential sticking can be a concern. Flow drilling is often conducted in situations where adequate reservoir energy exists such that the well would flow of its own accord. Underbalanced drilling is when the hydrostatic head of the drilling fluid is intentionally designed to be lower than the pressure of the formation being drilled. Annular pressure at point of inflow is directly related to the reservoir's ability to flow and the injected gas/liquid volumes. Underbalanced drilling requires detailed engineering analysis to increase the probability of success. Differential sticking is eliminated during underbalanced drilling and it entails the careful monitoring of bottomhole pressure.

4. More nitrogen in the drilling fluid is better

Injecting excess nitrogen compromises many underbalanced drilling operations. When an increase in nitrogen injection shows a positive response in terms of bottom hole pressure and rate of penetration, there is a tendency to further increase the nitrogen rate to try to maximize these benefits. There is a limit to the amount of nitrogen that a given system can tolerate. The purpose of injecting nitrogen is to decrease hydrostatic head and, consequently, bottom hole circulating pressure. Increases in nitrogen rate also increase fluid velocities and resultant frictional pressure losses. If too much nitrogen is injected especially in case of a small radial clearance, excessive frictional losses due to fluid velocity can overcome the benefits of reduced hydrostatic head. This may in the contrary lead to an increased ECD instead of a decreased pressure.

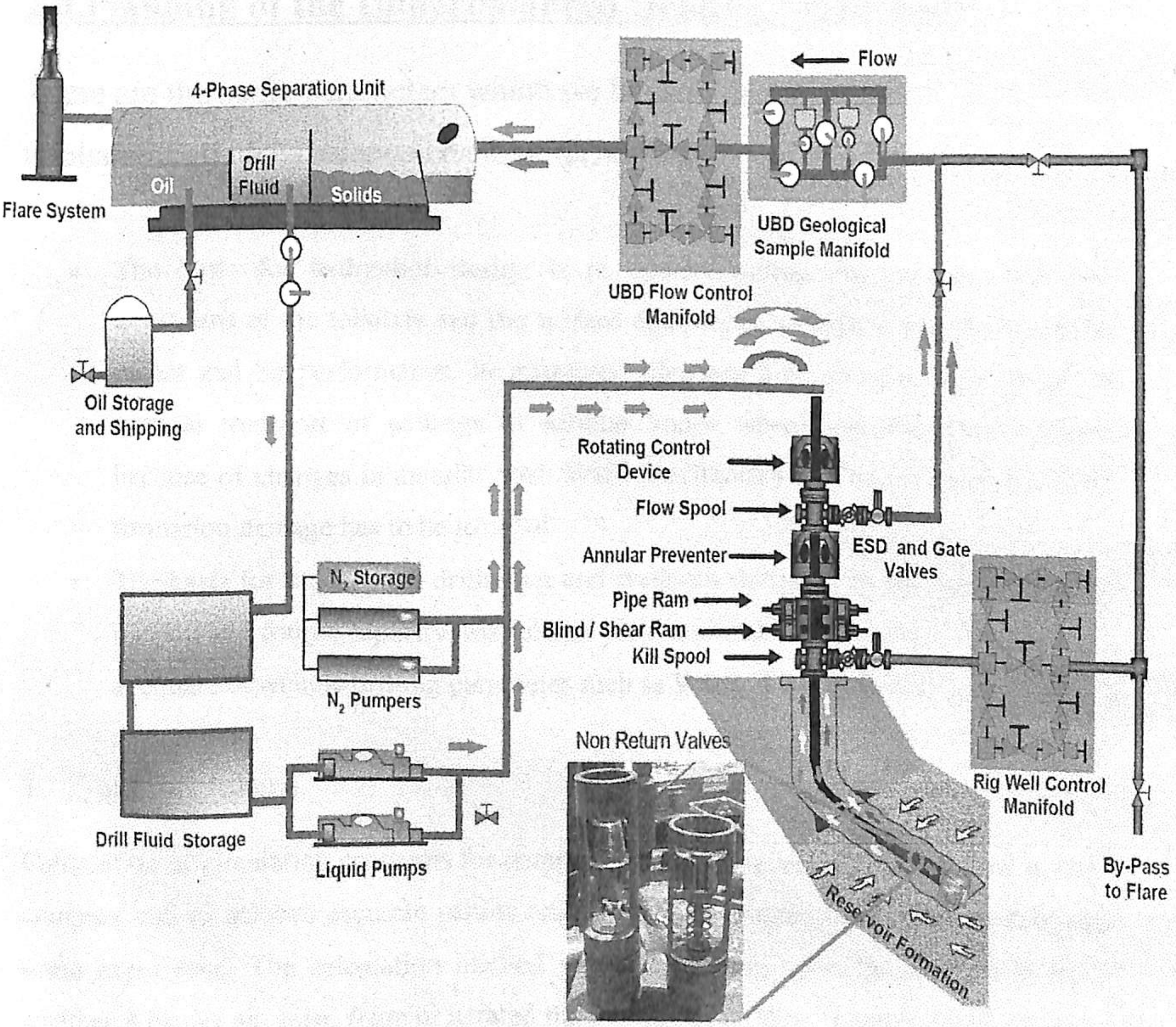
5. Underbalanced drilling can save marginal wells

Underbalanced drilling can help regenerate a well but is not a general solution to an Unproductive reservoir. Underbalanced drilling can improve the productivity of some wells, but it cannot affect the ability of a reservoir to transmit fluid. If productivity is restricted by formation damage near the wellbore, then underbalanced drilling may result in improved productivity. If the reservoir is tight and transmits hydrocarbons slowly, underbalanced drilling may not be economically feasible since little or no productivity increase would result. In order to determine the viability of any underbalanced operation, it must be first understood why a given pool/reservoir flows poorly.

6. Underbalanced drilling requires the use of coiled tubing

Current service rigs can drill slim-hole, reentry and horizontal holes underbalanced very successfully utilizing top drives as well as other technological advances in rotary rig operation, but there are a few points where coiled tubing can outperform conventional drilling and underbalanced drilling is one of them. When there is a must for successfully maintaining true underbalanced conditions (applications such as re-entry horizontal wells in depleted reservoirs, reservoirs with skin problems etc.) the ability of Coiled tubing operations to have continuous real time data transmission, necessary for underbalanced multiphase modeling as well as real time reservoir modeling, is essential. Because of the inability to truly monitor downhole conditions and accordingly adjust gas and fluid rates many "UB" conventional drilled holes had limited or no success. Another benefit of Coiled Tubing is it's ability to maintain continuous circulation and therewith prevent pressure surges and spikes. The major disadvantage of coil tubing is it's inability to rotate and therewith the increased change of cuttings accumulation. A good CT specialist is aware of this fact and trained to deal with this in an appropriate manner. The use of coiled tubing is often required but not a necessity to do underbalanced drilling.

1.4 Layout of Horizontal Drilling Technology



Layout of Horizontal Drilling
Fig: 1.2

Chapter 2

2.0 Planning of the Underbalanced Drilling Technology

These are the some parameters which we have to design before implementing underbalanced drilling technology

- The basis for hydraulics design is to operate within the pressure and rate constrains of the tubulars and the surface equipment, to ensure proper downhole motor and bit performance, to guarantee adequate hole cleaning and to ensure vertical transport of cuttings in annular zones where velocities are reduced because of changes in annular area. Wellbore Stability has to be maintained and formation damage has to be avoided.
- The basis for mechanical drillstring and wellpath design is to operate within the rig pull and torque capacity, the tubular yield and stability limits and to guarantee adequate downhole drilling parameter such as WOB, TOB or ROP.

1. Fluid mechanics

Calculation of circulating pressures for compressible gas or even multiphase flow is very complex and to achieve accurate results requires fairly complex theoretical models and some experience. The calculation method varies depending upon the used fluid type, whether it be dry air, mist, foam or aerated fluid in any of its flow regimes. Each situation demands a specific calculation procedure including consideration of annular injected gas phases or formation influxes. While complex, this information is required to perform other calculations that are essential to effective operation. Hole cleaning, Torque & Drag and motor performance all require an understanding of the fluid mechanics.

a) Hydraulics

A proper understanding of hydraulic modeling (the term Hydraulics should be understood as the theory of fluid mechanics for incompressible fluids only) is required for UBD applications where a liquid fluid (incompressible) is pumped through the standpipe and a gas phase (compressible) is injected into the annulus.

b) Compressible Fluid Flow Simulation

There is a program for analyzing drilling hydraulics problems associated with multi-phase compressible fluids, including wellbore inflow and drill cuttings transport. Particular consideration is in the downhole motor performance. The program covers four main applications of drilling with multi-phase fluids.

- The Two-Phase Fluid calculation mode provides detailed pressure loss and hydraulic parameter data for circulating the gas - liquid mixture through drillstring and annulus.
- The Mud with Gas Injection calculation mode combines the conventional mud hydraulics with multi-phase flow in the annulus. This mode is beneficial to analyze the influence of gas injection through a parasitic string or through the casing on the bottomhole pressure.
- The Foam calculation mode uses a specific viscosity correlation to characterize the rheology of a mixture of liquid, gas, and an additive to analyze the flow through drillstring and annulus.
- The Air Drilling is for the analysis of drilling with pure gas.

c) Hole Cleaning

Hole Cleaning in UBD applications presents the same problems as in conventional drilling. The flowrate required to clean a high angle well is much greater than that for vertical wells.

- **Gas and Mist Drilling**

Drillpipe rotation aids hole cleaning in an air drilled hole because cuttings are continuously agitated and ground finer by rotation, allowing the air to carry them out of the hole with relative ease. The volume of air that will clean the hole while drilling with rotary assemblies will not necessarily clean the hole during downhole motor drilling with no string rotation. When the formation is damp from water or oil, the cuttings form a "mud" that is deposited against the side of the hole. This tends to form rings of mud that, as the rings get larger, restrict the air flow and cause the pressure to increase. Mud rings can cause downhole fires and stuck pipe. The mud rings can be cut by detergent additions to the drilling fluid. A light mist often will cut mud rings. At high drilling rates, or with low gas volumes, the cuttings are carried up to the top of the collars where the annular area increases and the velocity drops. Cuttings cannot fall back to bottom, nor can they rise farther. They tend to form a floating bed that drops back as fill-up on connections. The solution would be to pump more gas or go to mist. Tight hole problems appear to be related to mud ring or floating bed problems. The important consideration is to not turn off the gas and to keep working the pipe. If the pipe is pulled up too hard it may stick tight. Sloughing or broken ledges, especially broken coal, can drop large pieces of rock on top of the collars mor bit. This can also occur with floating beds or by not cleaning the hole before stopping circulation. The important thing to remember is, not to jam the rock in place by turning off the gas and/or pulling too hard on the pipe. Circulate, rotate and work the pipe when using jointed pipe and circulate and pray for CT. Reservoirs, and other low permeability formations will weep fluid. This leads to bit balling and mud rings. Weeping will often end after the near wellbore fluids are depleted. Nitrogen or natural gas are particularly effective at drying a damp formation since they are dryer than air.

- **Foam Drilling**

One primary advantage of using a foam fluid for drilling is its superior lifting capacity compared to any other drilling fluid. The lifting force of a fluid increases as the liquid content decreases until an optimum point is reached. Past that optimum point the lifting force drops to zero and cutting transport is left solely depending on the annular velocity. In the foam region of gas to liquid ratios, the lifting capability of the fluid reaches a maximum. Besides the gas to liquid ratio the quality of the foam, largely affected by the foaming agent and the way the gas is blown into the liquid on surface, has a great impact on the lifting capacity. A well developed foam can suspend large cuttings even with the fluid circulation stopped. This can save time on connections, because the hole will not have to be circulated free of cuttings. If the foam begins to break down, slug flow can result. Slug flow is least efficient in cleaning the hole. Near the transition point from foam to mist regimes, the foam achieves its best lifting capability. Unfortunately, this region of foam quality is difficult to maintain and will not be achievable all along the wellbore due to different pressure levels at bottom and at surface. Compared to air and mist, where cuttings transport entirely depends on velocity, foam will carry larger cuttings past the drill collars. The change in velocity above the collars may not induce fall-back because the lifting is dependent on viscosity.

- **Aerated Fluid Drilling**

In wells drilled with aerated fluids, the cuttings transport is dependent on flow velocity and the hole cleaning considerations will not be different from conventional drilling applications.

2. Torque & Drag

Torque & Drag calculations differ in underbalanced wells due the reduced density of the drilling fluid increasing the normal forces and the changes in friction coefficient depending upon the fluid type. A typical coefficient of friction when drilling with air is 0.4 to 0.5, for foam typical values are in the range of 0.4. Caution is urged in selecting friction coefficients since the greatest influence in friction factors is the contaminants (liquids, cuttings) that are in the interface between the two components. For example, if the well, drilled on air is producing water or oil, the friction factors will drop accordingly.

Conventional incompressible drilling fluids have an essentially linear increase in hydrostatic pressure with depth. The density of the drilling fluid does not vary significantly when circulating. With air, mist, foam or aerated fluids, the circulating fluid density can vary significantly over the length of the string and the circulating densities can be dramatically different from the static case. Additionally, the drilling fluid inside the drillstring has typically higher density than in the annulus.

3. Hole Stability

- **Mechanical Instability**

Mechanical instability includes situations where the fluid density is not sufficient to keep the formation in question from falling or caving into the hole. The formation is driven into the borehole by pressure trapped in the formation. The pressure may be the result of tectonically induced stress or abnormal pressure. It also may simply be due to poor cementation of the rock particles (e.g., unconsolidated sandstone).

- **Chemical Instability**

Chemical instability is the result of a chemical reaction between the formation and the fluid in the wellbore. A good example is the reaction between water-based drilling fluids and a water sensitive shale or clay in the formation.

The surface indications of wellbore instability are very much the same, regardless of the type of instability. They include:

- High torque
- Increased drag
- Fill on connections
- Difficulty in pulling off bottom, or in pulling the first few stands
- Pressure increases when circulation begins, then decreases once circulation is well underway

2.1 Overview of Multiphase Flow Simulation

Introduction

Multiphase flow simulation is an integral element in the preliminary engineering, circulating system design, well controllability analysis and equipment selection process for any underbalanced drilling operation. The primary goals of multiphase flow modeling are to:

- Investigate the possibility of achieving a stable underbalanced or near-balanced condition down hole.
- Ensure adequate annular velocities and/or transport properties for hole cleaning can be achieved in an underbalanced circulating system.
- Confirm that the operating performance of the down hole tools (motor and MWD) is not negatively affected by the underbalanced circulating conditions.
- Establish the down hole and surface operating envelope for the planned underbalanced operation.
- Establish the expected operational parameters such as injection rates, injection pressure, bottom hole and surface annular pressures, maximum surface return rates, etc.
- Identify the technical specifications required and design parameters for all UBD equipment.

The main focus of multiphase flow modeling in the context of UBD is to establish a pressure profile along the entire circulating path. This requires combination of conservation principles with closure relationships such as PVT relationships. In general, a complete UBD flow modeling software program should include, at a minimum, the following features:

- A flow regime (or flow-map) model, which predicts the two-phase flow regime at any given location in the flow path,

- A liquid hold-up model, to calculate the liquid fraction at any given location, taking into account the slip between phases,
- A model for predicting frictional pressure losses in a two-phase flow system. Although hydrostatic pressure loss may dominate the total pressure loss, frictional pressure drop is an important contribution to the bottom hole pressure, and must be accurately modeled, especially in friction-dominated systems,
- Thermal, PVT and property models to account for the effect of temperature and pressure on the phase behavior and transport properties of the fluids,
- A model to predict hole cleaning performance

The Recommended Modeling Sequence

The following discussion describes a methodology used for circulating system design which ultimately provides insight into the complexity of an underbalanced candidate, equipment suitability and well controllability. This methodology is based on theoretical basis for multiphase flow analyses as well as practical understanding and experience gained in UBD operations worldwide. The modeling sequence may be applied in every technical feasibility study of a UBD candidate. However, the extent of reservoir uncertainty for a candidate will dictate the degree of sensitivity analyses required to develop the sought "robust" design.

The first step in UBD multiphase flow modeling is to model the annular pressures and velocities assuming no flow from the formation. This is done to determine what combination of liquid and gas gives the desired pressure drawdown across the reservoir section. Specifying the surface pressure and the liquid and gas that will be exiting the bit allows for the modeling of the annulus. The model calculates the resulting pressure profile in the annulus, and thus the bottom hole pressure. Alternatively, the bottom hole pressure can be specified with the liquid and gas exiting the bit and the model will calculate the pressure profile and resulting surface pressure. Specifying the surface pressure and calculating the bottom hole pressure is the preferred method, but in many cases the bottom hole pressure must be specified to achieve the desired pressure drawdown. This needs to be repeated for both the well's kick off case (bit at shoe) and for the well's total depth case (bit at TD) to determine the variation (if any) in circulating parameters over the lateral length. Additional bit locations may also have to be modeled for a long lateral section.

This portion of the multiphase modeling provides insight into the complexity of achieving an underbalanced state, optimal gas and liquid injection rates, hole cleaning efficiency, motor throughput volumes and optimal gas injection method (i.e. drill pipe).

Alternative Designs

In some cases, it is not possible to find combinations of liquid rate, gas rate and choke pressure that meet all three of the design criteria: pressure drawdown, minimum liquid velocity for adequate hole cleaning, and motor flow-through limits. In such cases, either the concept of underbalanced drilling must be abandoned, or the design assumptions must be changed. Three immediate options are available to change the design concepts.

First, the fluid system can be changed (water to crude, or use of foam for example). Changing the fluid system from two-phase flow to foam will significantly reduce the liquid velocity requirements to achieve adequate hole cleaning. This change will be significant where there is a change in hydraulic diameter (i.e. at the top of a liner where velocity problems occur). However, while solving hole cleaning problems, this solution may compromise the pressure drawdown requirements (especially if foam is used).

Second, wellbore geometry can be changed (by running a tie back string for example). Changing the wellbore geometry will significantly change the liquid velocities required for adequate hole cleaning and may also impact the injection volume requirements.

Finally, alternative injection methods can be evaluated (i.e. concentric casing for example). Changing from drill pipe conveyed gas to concentric casing injection would eliminate concern's about down hole tool limitations such as motor volume limitations or MWD equipment (gas fraction restrictions). However, modifying the gas injection method may have no impact on hole cleaning problems as available gas injection points are typically above the areas where the most severe hole cleaning problems are encountered. Also, annular injection of gas usually increases the gas volume requirements in attempt to minimize concentric annular accumulation effects.

Step 2: Determining the UBD Operating Window

Once the flow simulations are completed, taking into account all relevant well information, an underbalanced operating window may be developed. Only those combinations of liquid, gas and surface choke pressures that meet the pressure drawdown requirement, minimum liquid velocity requirement and are within motor limits, are acceptable. The "window" allows for a better understanding of the possibility of successful underbalanced drilling operations. For example if all the UBD constraints are satisfied (UBD pressure, hole cleaning, and motor performance) and the operating envelope is large, the preliminary engineering of the UBD potential appears promising. However, if the window is very small or nonexistent, then perhaps more thorough reservoir information, excess equipment or modifications in casing design may be required. The UBD operations window is bounded by the following constraints:

- Upper pressure boundary - The underbalanced pressure is typically designed to be *at least* 700 kPa less than reservoir pressure. This is to compensate for model errors, and to ensure overbalanced pressure spikes do not occur during the inevitable wellbore transients such as periods of pump-off (connections) or surge and swab effects. Lower limits may be acceptable if the PVT behavior, reservoir parameter uncertainties and procedures are better understood. Higher limits may be needed if spontaneous imbibition is a concern.
- Lower pressure boundary – The maximum allowable pressure drawdown to prevent wellbore collapse (borehole stability), high return surface volumes, fines migration and water/gas coning. In a mature field, the maximum drawdown allowable is assumed from typical production drawdown.
- Lower fluid (liquid and gas) injection boundary –Typically bound by minimum liquid velocity for adequate hole cleaning but in some rare cases may be bound by minimum operating volume of the down hole tools (motor or MWD).

- Upper fluid injection boundary – Typically bound by motor maximum throughput but in some cases may be further restricted by injection or MWD equipment. For instance, a typical membrane nitrogen unit has a maximum output of 1500 scfm (~40 m3/min), this may further restrict the operating window. The other common upper fluid limit restriction would be the operability of conventional MWD equipment.

Step 3: Modeling Injection Pressure & MWD Operability

Once the annulus pressures and velocities have been determined, the model is utilized to calculate the injection pressures and the equivalent liquid volume through the motor. For these calculations, the volume of liquid and gas pumped into the standpipe is specified along with the bottom hole pressure. The combination of liquid and gas volumes and bottom hole pressure should be the same as those determined from the annulus calculations. The model then calculates the surface injection pressure (standpipe pressure) and the equivalent volume through the motor.

Given the requirement for underbalance, the maximum steady state injection pressure occurs at a bottom hole pressure equal to the reservoir pressure. Also, if drill pipe gas injection is utilized, the pressure drop across the motor will vary significantly with torque. Therefore, while off-bottom the motor pressure drop will be lower than while on-bottom. The off-bottom case is used for determining motor optimum throughput volumes while the on-bottom case is used for maximum injection pressure determination.

Once the combination of injection pressures and injection rates are known the gas volume fraction (GVF) profile in the drill pipe (and hence the maximum GVF in the drill pipe) may be determined. This is usually determined at the minimum circulating bottom hole pressure conditions, and with the maximum gas rates within the operating envelope. This is of importance to determine the operability of the conventional MWD equipment. Mud pulse telemetry has proven unreliable for GVF between 8% and 28%, depending upon the pulsing method and manufacturer.

The results of this modeling are used to determine down hole tool limitations (motor, MWD), mud pump requirements (liner sizing) and gas compression requirements. It is important to note that the higher the maximum injection pressure, the more gas compression equipment that will be required (especially in the case of membrane nitrogen). Therefore, steady state injection pressure determined (with safety factor) should dictate the compression requirements and operating procedures should be developed to stay below this maximum (i.e. unloading the wellbore).

Step 4: Modeling with Reservoir Inflow

Once the no-influx UBD operating parameters are established, modeling must be repeated considering reservoir inflow. It is often overlooked in UBD operations design that a UBD operation is as much a production situation as it is a drilling situation, and hence, all of the issues critical to production analysis are critical in UBD operations as well. The marginal attention given to inflow in modeling UBD operations is apparent in that most production analysis software tools contain sophisticated algorithms and approaches for the modeling and consideration of inflow while very few of the UBD simulators have this facility.

Faced with such a situation, UBD Engineers typically resort to either specifying a volume of influx (without explicit consideration of the dependence of the volume on local productivity or drawdown), or simply modeling additional fluid injection and evaluating impact on the operating window. The logic for this approach typically has been that as gas enters the annulus, the impact is similar to injecting more gas to the annulus, and therefore its effect on the bottom hole pressure is indicated by the pressure behavior at high gas rates. Unfortunately, as even the most rudimentary production analysis will reveal, this approach does not adequately capture the coupling between inflow and wellbore pressure, or more accurately, the wellbore pressure profile along the flowing interval. Moreover, inflow performance relationship is almost always non-linear with drawdown, as any IPR curve will show. For oil reservoirs, the behavior can be treated as linear in most cases, thus allowing modeling with a simple linear productivity index.

However, for gas reservoirs, the relationship can be quite non-linear, and this non-linearity should be respected in the estimation of influx volumes. Finally, wellbore pressure at the toe (or deeper portion) of an open interval is higher than that at the heel (or shallower portion) of that interval. As a result, the contribution to inflow across the open interval from different parts of the formation will be different. This situation is further complicated if the open interval traverses formation sections with different productivity indices for wells with long intervals.

In modeling inflow, it is useful to work with Production Engineers familiar with the subject reservoirs to establish the inflow performance relationship and PVT behavior models, both of which are critical in accurately establishing UBD
operability under inflow conditions.

Modeling with inflow must again assure that the underbalanced state is maintained throughout the open hole section, that the motor limits are not exceeded and that adequate hole cleaning is maintained. The multiphase model will calculate the outflow from the well, including the fluid that was pumped into the well and the fluid produced from the reservoir. The surface equipment must be designed for total fluid assuring proper retention time for separation of the fluids and solids. Surface piping must be sized so that line pressures do not affect the bottom hole pressure or the pressure limits of the pressure vessels.

Extensive sensitivity analysis is usually required when modeling with inflow if any uncertainty exists in reservoir pressure, reservoir fluid properties and PVT behavior, or productivity indices. This is typically the case since reservoirs are never fully homogenous. In addition, if underbalanced is being applied in the candidate reservoir for the first time, the UBD PI will not be known. Extensive production data may be available to determine the average field PI but an irrefutable UBD PI will likely not. Therefore, adequate PI sensitivity is required to encapsulate robustness in design. Suryanarayana et. al. discuss such sensitivity analyses for a gas-condensate situation.

For this part of the design it is also important to model various open hole depths, and to use the expected productivity with UBD, rather than conventionally realized productivity (this can be critical for reservoir application of UBD). Depending on the productivity of the reservoir, it is suggested that as much as 200 meter increments be modeled with the productivity expected during UBD. The primary purpose of this approach is to ensure that the well does not become overbalanced at the bit due to high productivity along the remaining lateral. This phenomenon is often referred to as the "heel – toe" effect which may guide the maximum lateral length of an underbalanced candidate.

The results of the maximum expected PI case are then used to prescribe the required surface handling system by determining the maximum surface return volumes. Depending on reservoir uncertainty and the transient nature of underbalanced drilling (steady state model predictions), additional safety factors are still used in order to ensure adequate equipment specifications.

Step 5: Well Controllability

The final step in the analysis is to consider the "controllability" of the well, i.e., how controllable is the bottom hole pressure by varying the surface choke setting (and hence the back pressure)? By design, the two ways of controlling or affecting the bottom hole pressure are to either change the injection parameters - gas and liquid rates, or to change the choke setting.

It is important to know the relationship between the backpressure and bottom hole pressure (and return flow rates), as this gives a feel for the controllability of the well6. It also establishes a surface operability envelope, which can be used to control down hole conditions in terms of surface measurable parameters.

For instance, if the relationship between BHP and backpressure is linear, it is indicative of good control on the BHP solely by use of backpressure as there is a monotonic relationship between an increase in surface backpressure and decrease in BHP. This is typical in many cases, especially in low-rate oil wells. If, on the other hand, the relationship is non-linear, and shows a peak pressure, it is indicative of complicated controllability situations. It is therefore clear that well controllability analysis must be conducted during the modeling sequence.

The results of this modeling sequence may be used to develop BHCP versus flowing wellhead (or choke) pressure curves. The maximum allowable wellhead pressure, at maximum UBD PI, is determined by the choke pressure applied before the well becomes overbalanced. It is important that this analysis is conducted for both circulating (injecting fluid) and for production (if the well is capable of natural flow). The maximum wellhead pressure calculated is used to specify the dynamic rating of the rotating control head (RCH). The static rating of the RCH remains as the Maximum Allowable Surface Pressure (MASP), which must always be calculated for a gas gradient to surface for UBD design.

Step 6: Equipment Specifications

The final stage in the strategy is to summarize the parameters of the UBD equipment including safety factors. The process of flow analysis described above continues iteratively until the applicable operating parameter range is identified, together with injection and well controllability boundaries. With all of these model results (including adequate sensitivities) it now becomes possible to confidently specify equipment requirements. How each modeling sequence contributes to equipment sizing is further summarized in Table 2.1 below:

SUMMARY OF OPERATING PARAMETERS USED FOR EQUIPMENT SIZING			
Specific Parameter	Model Sequence	Equipment Impact and Sizing	Comments
Total Return Gas Rate	From flow model with Inflow (max UBD PI)	Separator / Flare Sizing / Re-Compression Equipment (Optional)	Highest rates possible from maximum drawdown, for high rate reservoirs inflow will dominate returns.
Total Return Hydrocarbon Rate	From flow model with Inflow (max UBD PI)	Separator / Storage Tanks / Export Pump(s) / Production Facility	Highest rates possible from maximum drawdown, for high rate reservoirs, inflow will dominate returns but if drilling with crude usually injection dominates.
Total Return Water Rate	From flow model with Inflow (max UBD PI)	Separator / Storage Tanks / Export Pump(s) / Production Facility	If drilling with water, injection will always dominate returns.
Solids Return Rate	Based on hole size, ROP, well integrity	Separator / Storage / Shaker / Centrifuges	Depends on length of lateral and ROP. Take into account increase in ROP due to UBD.
Maximum Gas Injection Rate	From flow model without Inflow (usually) at TD	Volume / Storage / Compression	Highest required rate usually for total depth with no inflow anaysis (especially with gas wells).
Maximum Liquid Injection Rate	From flow model without Inflow (usually) at TD	Storage / Chemical Requirements	High end typically for no inflow case (especially for oil wells) dictated by hole cleaning.
Maximum Injection Pressures	From injection modeling with BHCP equal to reservoir pressure	Mud Pump Liner Sizing / Compression Equipment	High end from maximum potential gas and liquid injection rates at maximum bottomhole pressure (res press) with max pressure drop across downhole tools.
Maximum Gas Volume Fraction	From injection modeling, max gas rate required	MWD Operability / Gas Injection Method	MWD will not function at ~22% GSF. Taken from lowest potential injection pressure in the UBD operating window.
Motor Throughput Volume	From injection modeling, max fluid rates required	Motor Selection	High end from maximum potential gas and liquid injection rates in UBD window.
Maximum Choke Pressure	From controllability sensitivity analysis	Rotating Control Head / Choke / ESD / Piping	Maximum choke pressure with max inflow (UBD PI) before the well becomes overbalanced. Sets the dynamic RCH rating.
Maximum Anticipated Surface Pressure	From Drilling Practice (casing design) MASP	Rotating Control Head / Choke / ESD / Piping	Taken from the lesser of fracture at shoe minus gas gradient to surface or reservoir pressure minus gas gradient to surface.
Annulus Surface Temperature	From Thermal modeling	Separator / Valves / RCH	Sets the temperature rating of the RCH and valving.
Annulus Bottomhole Temperature	From thermal modeling (10% less than reservoir temp)	Downhole Tools	Sets the requirements for BHAs and motors. Maximum will be static BHT.

Table 2.1

Margins of Safety in Design

The above discussion forms the theoretical and modeling basis for the design of an underbalanced well, and the major equipment needed in the operation. In practical design, it is necessary to specify equipment with adequate safety margin. Margins should be applied to the pressure, volume, and rates specified for the equipment. The margin also depends upon the safety criticality and the likely uncertainty in the design ranges that result from the modeling. Summarized below are the safety margins and levels of redundancy recommended for different parameters and equipment components in a UBD operation.

Table 2.2 lists the recommended margins for the injection equipment. In addition to the safety margin in the pressure rating of the equipment, the volume requirements must also be specified with a margin of safety. In addition, redundant equipment should at least be identified and made easily accessible (if not physically on location, at least within timely reach) for equipment susceptible to breakdown such as pumps and compressors.

Parameter/ Equipment	Safety Margin / Redundancy	Comments
Gas Injection (Rate Based)	1.5 x max injection rates	Used for membrane unit, compressors & exhaust gas
Gas Injection (Volume Based)	2 x Total Volume	Used for cryogenic nitrogen. 100% redundancy is for project availability. Based on lowest expected ROP. Logistics and supply will dictate field availability.
Injection Pressure	1.25 x max injection pressure	Max injection pressure based on ECD @ reservoir pressure and minimum (off bottom) pressure drop across the motor.
Pumps and Compressors	2 X Redundancy	On site back-up, adequate rebuild parts or immediate availability.

Table 2.2

Table 2.3 lists the safety margins recommended for the down hole equipment. The motor limits and their impact on the UBD operating window has been discussed however, in specifying the motor, a margin of safety should be imposed on specified temperature and volume rating. It is prudent to use the static bottom hole temperature (BHT) in the specification of motor or MWD equipment temperature ratings, since the BHT could be reached in underbalanced drilling during prolonged periods of very low or no circulation.

Parameter/ Equipment	**Safety Margin / Redundancy**	**Comments**
MWD Temperature Rating	1.1 times static BHT 2 X redundancy	Likely during connections and trips
Motor Temperature Rating	1.1 times Static BHT 2 X redundancy	Likely during connections and trips
Motor Volume Rating	1.1 times required equivalent flow limits	Maximum equivalent flow required for adequate operating Window

Table 2.3

Table 2.4 lists the recommended safety margins for the safety critical pressure control equipment. Notice that for both chokes and rotating control head margins, the design bases and margins of safety may not always be achievable.

Parameter/ Equipment	Safety Margin / Redundancy	Comments
Rotating Control Head Ratings	Static: 1.1 times MASP Dynamic: 1.25 times max back pressure during operations (ECD=Res. Pressure) Temperature: 1.25 times maximum anticipated surface temperature	Lower MASP should be assumed for static ratings. MASP gas to surface may be difficult to obtain due to currently available RCHs.
Rotating Control Head Redundancy	As required	Redundancy is generally required of wear-sensitive parts such as elastomers. Unit redundancy is not common, but may be desirable for long UBD operations in remote locations.
Choke Pressure Rating	Based on MASP from reservoir at its highest expected pressure.	May be difficult. Alternative designs for safety (high pressure separation system).
Choke Redundancy	2 X redundancy	Almost all UBD chokes give a 2 X redundancy.
BOP Equipment	Based on MASP from reservoir	Usually Rig BOP already designed to this at higher Reservoir Pressure

Table2.4

Table 2.5 lists the recommended margins of safety for surface returns handling equipment. Rate capacity safety margins for the flare are slightly higher than for the separator since the separators could be bypassed with flow directed to the flare in the event of an emergency.

Parameter/ Equipment	Safety Margin / Redundancy	Comments
Separator Rate	1.25 x maximum anticipated rates	Max rates at highest likely drawdown and reservoir PI
Separator Pressure	1.25 x system back pressure	High pressure separator in high rate, high pressure reservoirs
Flare Rate	1.5 x maximum anticipated rates	Self-igniting. May have noise and temperature restrictions.
Piping	1.25 x MASP upstream of separator 1.25 x working pressure downstream of separator	Based on piping friction loss analysis. Sizing based on minimizing working pressure (or system back pressure)
Pumps	1.25 x max working pressure if re-injecting 2 x redundancy 1.5 x anticipated maximum flow rates	Max working pressure based on pressure loss and receiving system pressure
Solids Handling	1.5 x solids rate at highest ROP	Theoretical hole volume is rarely observed at surface.

Table 2.5

Chapter 3

3.0 Surface Equipment For UBD Operations

The surface equipment for underbalanced drilling can be broken down into 4 main categories. These are:

- Drilling system
- Gas Generation Equipment
- Well Control Equipment
- Surface Separation Equipment

3.1 Drilling System

Hole size and reservoir penetration as well as directional trajectory will determine whether coiled tubing or jointed pipe is the optimal drillstring medium. If the hole size required is larger than 6-1/8", jointed pipe may have to be used. For hole sizes of 6-1/8" or smaller coiled tubing can be considered. Presently the size of coiled tubing used for drilling operations is between 2" & 2-7/8" OD. This is due to many factors including, flow rate through the coil, pressure drop through the tubing, WOB, profile of the well, maximum pick-up weight, both in hole and the surface equipment and weight of the coiled tubing itself. It may be at times that the ideal coiled tubing for an operation may be excluded due to other factors, such as crane or transport limitations or the life of the coil may not be feasibly economical.

Coiled tubing generally has several advantages and disadvantages over jointed pipe systems. For jointed pipe systems drill string properties and tripping under pressure will need to be considered. Installation of a snubbing system on a platform or rig with a fixed distance between rotary table and wellhead may cause severe problems. Several operations on land rigs had to be re-designed to accommodate rig assist snubbing systems.

3.1.1 Coiled Tubing versus Jointed Pipe

Coiled Tubing	Jointed Pipe
No connections made during drilling	Connections require gas injection shut down causing pressure peaks.
Higher pressure containment	Pressure of Rotating Diverters limited to 3000 psi.
Stiff Wireline makes MWD systems simpler in gasified fluids	MWD systems not reliable in gasified systems
No snubbing system required	Pressure deployment requires snubbing unit
Maximum hole size 6"	No hole size limit
Hole cleaning more critical	Hole cleaning can be assisted by rotation
Potential for pipe collapse in high pressure wells	Special drillstring connections required for gas fields
Thru tubing drilling work possible	Thru tubing work requires special rig floor tools on conventional rigs
BOP stack smaller	BOP stackup requires rotating diverter system.
Costs are lower	Higher costs as a result of rig.
Limited with drag for outreach	Ability to drill long horizontal sections

Table 3.1

3.2 Gas generation Equipment

3.2.1 Natural Gas

If natural gas is used for underbalanced drilling a natural gas compressor maybe required. This will have to be reviewed once the source of the gas is known. Most production platforms will have a source of high pressure gas. A flow regulator and pressure regulator will be required to control the amount of gas injected during the drilling process.

3.2.2 Cryogenic Nitrogen

The use of tanked nitrogen can be considered on onshore locations where a large truck can be used for supply of nitrogen. Cryogenic nitrogen in 2000 gal transport tanks provides high quality nitrogen and uses equipment that is generally less expensive. Liquid nitrogen is passed through the nitrogen converter, where the fluid is pumped under pressure prior to being converted to gas. The gas is then injected into the string. Generally, the requirement is for the nitrogen converter and a work tank with additional tanks being provided as necessary. For operations in excess of 48 hrs, the requirement for liquid nitrogen can be quite large, which can result in logistical difficulties.

The use of cryogenic nitrogen offshore is sometimes not recommended depending on the application. Pumping 1500 scft/min of nitrogen for a 24hr drilling period would require 15 tanks of 2000 gal each. Moving this on and off an offshore platform is a significant task and would have some serious safety implications. If drilling continued at this rate for several days, two dedicated supply boats would be required to maintain supply.

In order to move away from tank transport for large nitrogen dependant drilling operations, the use of nitrogen generators is often recommended offshore.

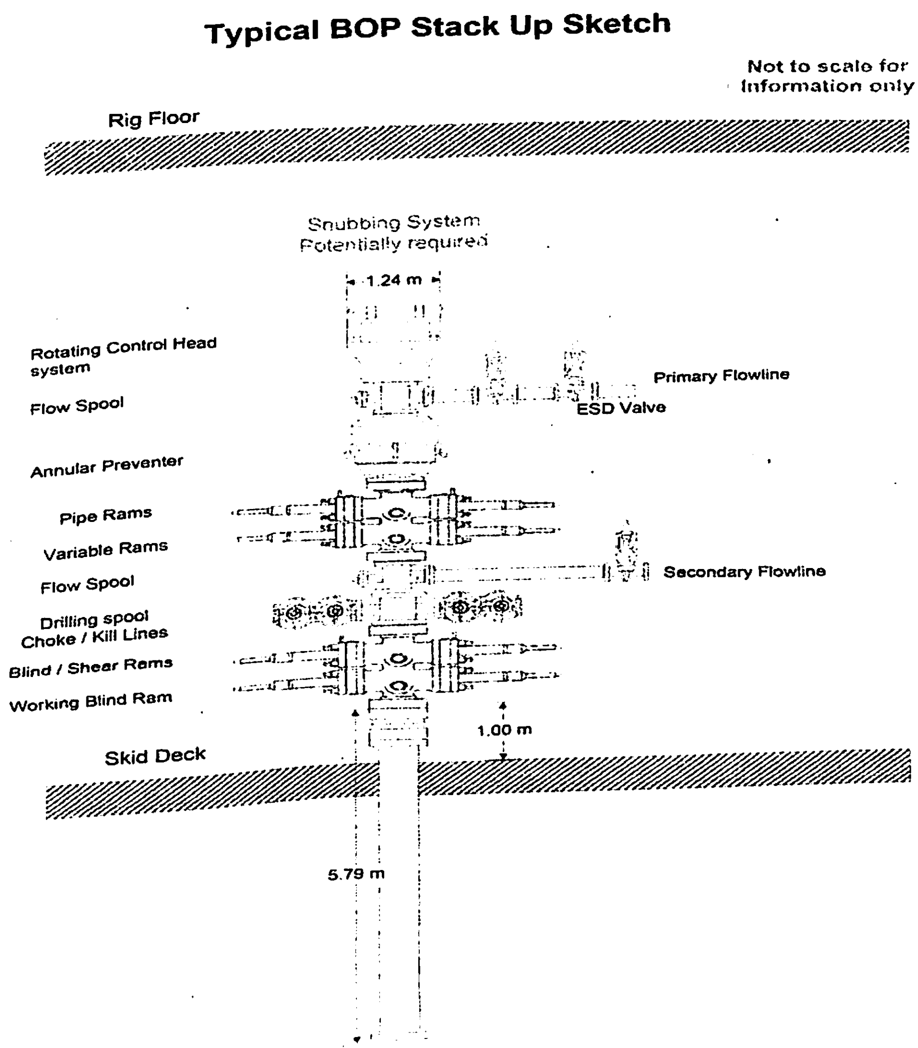
3.2.3 Nitrogen Generation

A nitrogen generator is no more than a filter system that filters nitrogen out of the atmosphere. A nitrogen generator uses small membranes to filter the air. Oxygen

3.3 Well Control equipment

The conventional BOP stacked used for drilling is not compromised during underbalanced drilling operations. The conventional BOP stack is not used for routine operations and will not be used to control the well except in case of emergency.

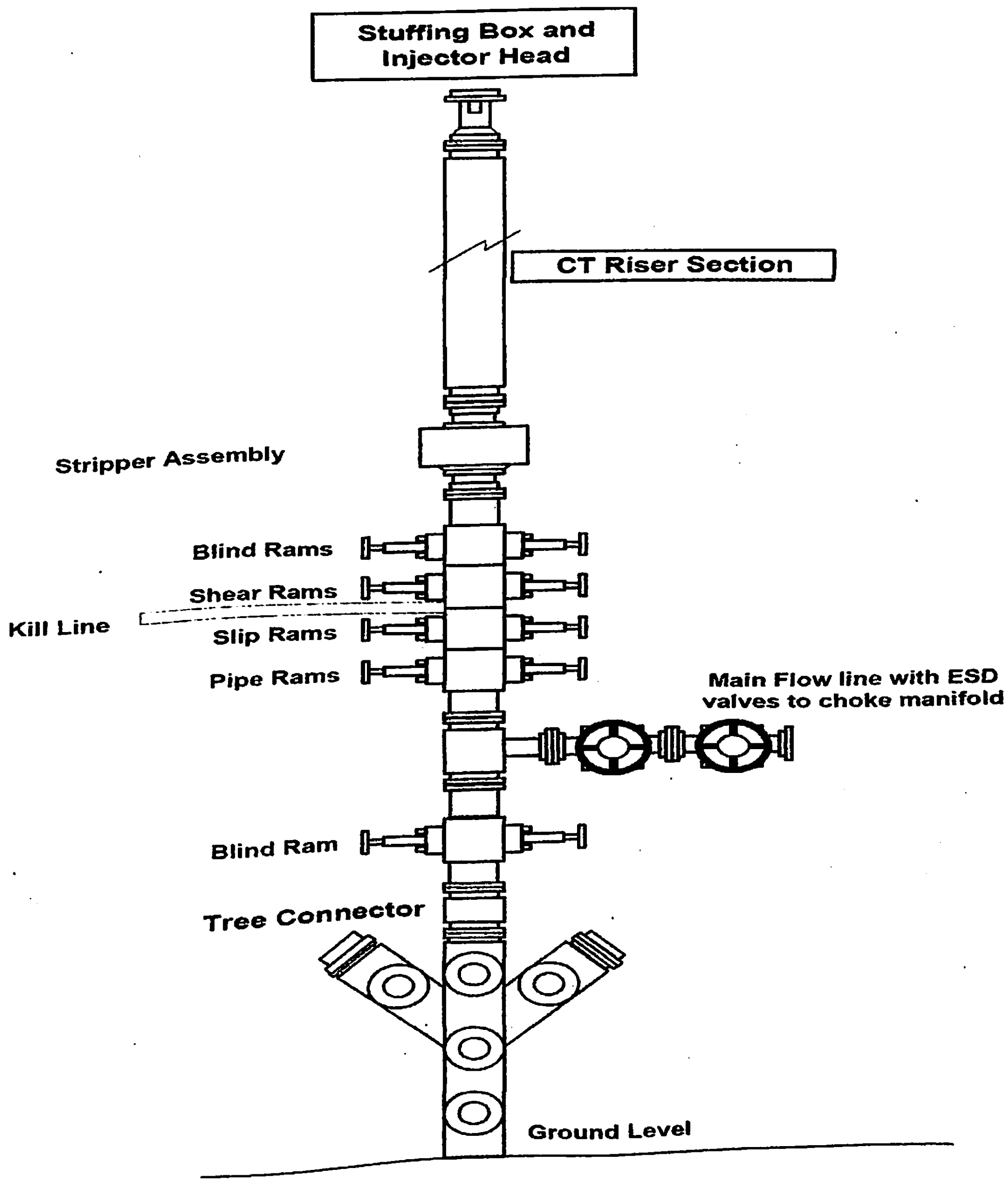
A rotating control head system and primary flowline with ESD valves is installed on top of the conventional BOP. If required a single blind ram, operated by a special koomey unit is installed under the BOP stack to allow the drilling BHA to be run under pressure.



BOP Stack Up
Fig 3.2

3.3.2 Coiled Tubing Systems

Well control when drilling with reeled systems is much simpler. A lubricator can be used to stage in the main components of the BHA or if a suitable downhole safety valve can be used then a surface lubricator is not required and the injector head can be placed directly on top of the wellhead system.

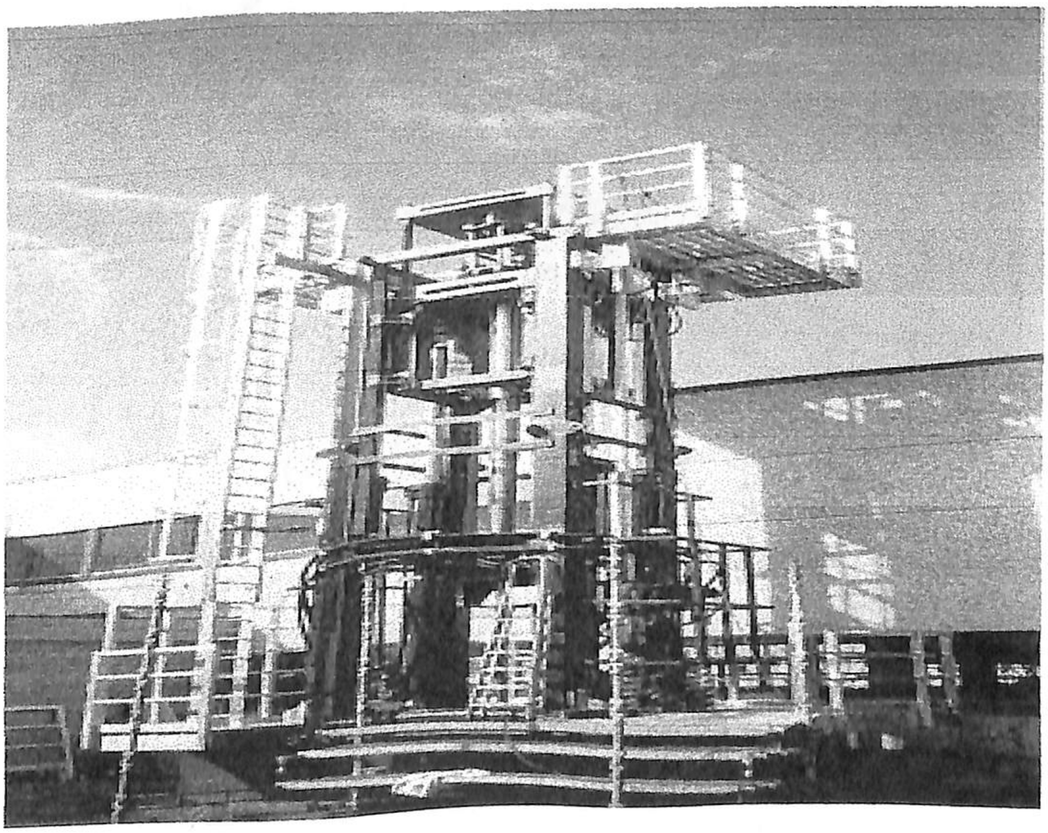


Stuffing Box & Injector Head
Fig 3.3

Reeled systems can be tripped much faster and the rig up is much simpler. One consideration that must be made with reeled systems is the cutting strength of the shear rams. It must be verified that the shear rams will cut the tubing and any wireline or control line systems inside the coil. For a stand-alone operation on a completed well an example stack up is shown here.

3.4 Snubbing system

If tripping is to be conducted underbalanced, a snubbing system will be installed on top of the rotating control head system. The current systems used offshore are so called rig assist snubbing systems. A jack with a 10ft stroke is used to push pipe into the hole or to trip pipe out of the hole. Once the weight of the string exceeds the upward force of the well, the snubbing system is switched to standby and the pipe is tripped in the hole using the drawworks. The ability to install a snubbing system below the rigfloor allows the rig floor to be used in the conventional drilling way.

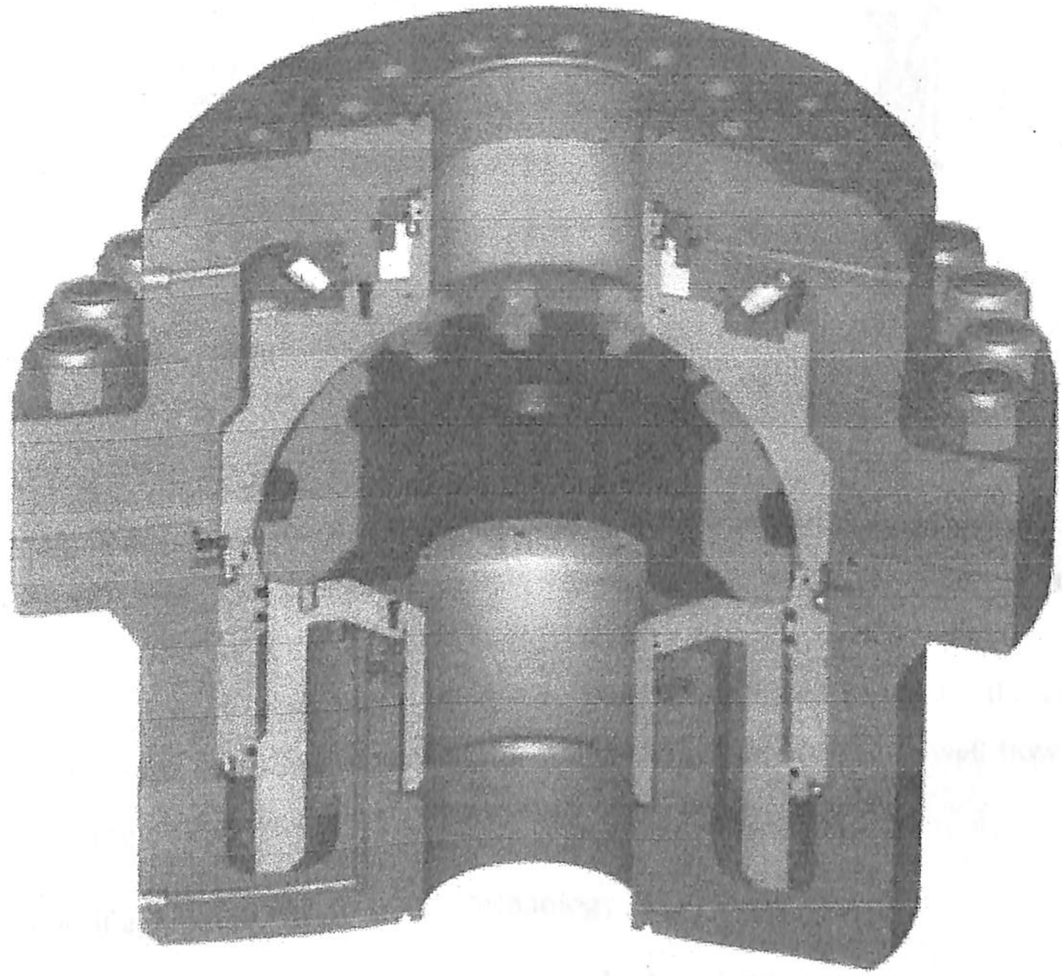


Snubbing System
Fig 3.4

3.5 Rotating Control Head System

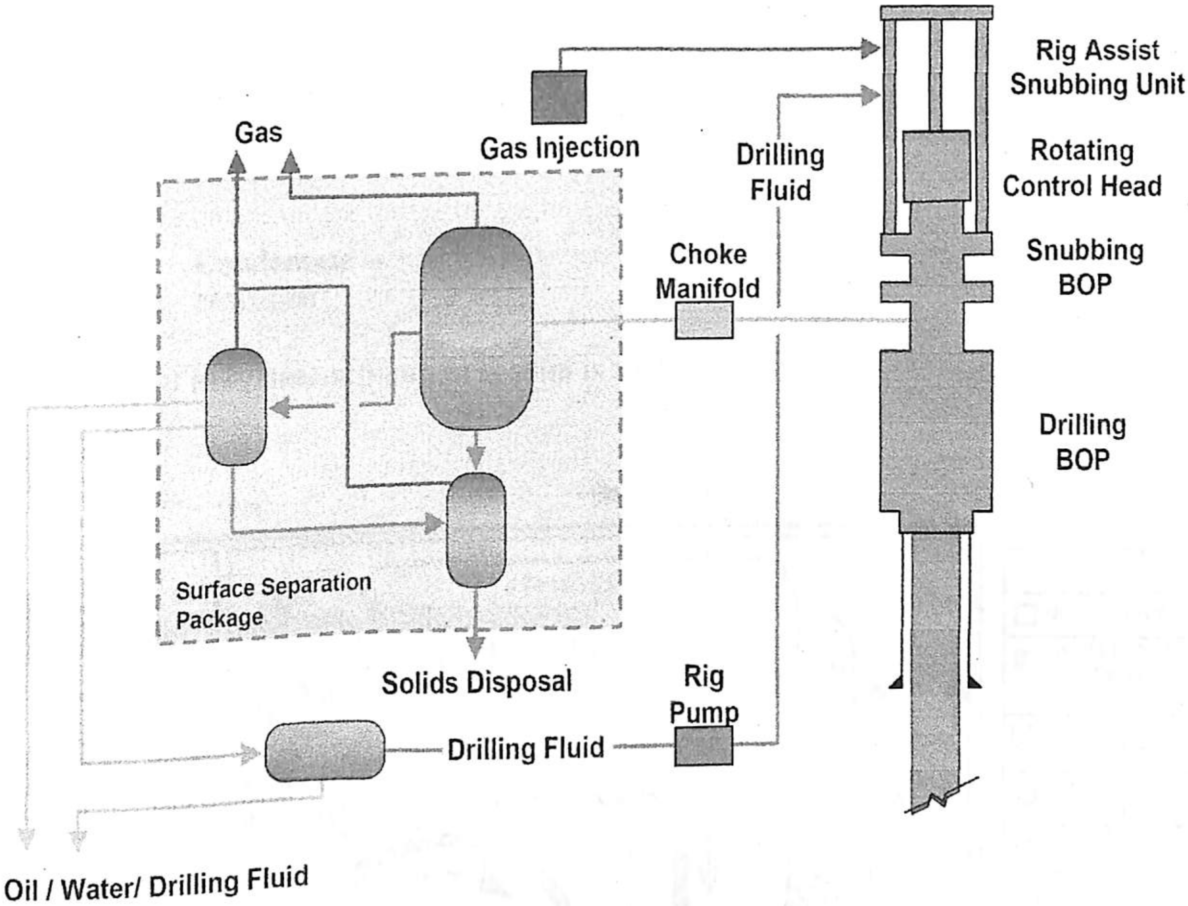
The rotating control head system will need to be sized and selected on the basis of the expected surface pressures. A well with a reservoir pressure of 1000 psi does not need a 5000psi rotating control head system. A number of companies offer rotating control head systems for underbalanced drilling.

The ESD system on an underbalanced drilling operation closes in the well at the main flowline and shuts down fluid pumps and gas lift systems. The ESD system can be remotely operated from a number of locations on the rig when drilling underbalanced.



Rotating Control Head
Fig 3.5

3.6 Separation Equipment



Separation System
Fig 3.6

The equipment used onshore in the early days of underbalanced drilling was too large to be taken offshore. The separation system has to be tailored to the expected reservoir fluids. A separator for a dry gas field is significantly different from a separator required for a heavy oil field. The separation system must be designed to handle the expected influx and it must be able to separated the drilling fluid from the return well flow so that this can be pumped down the well once again.

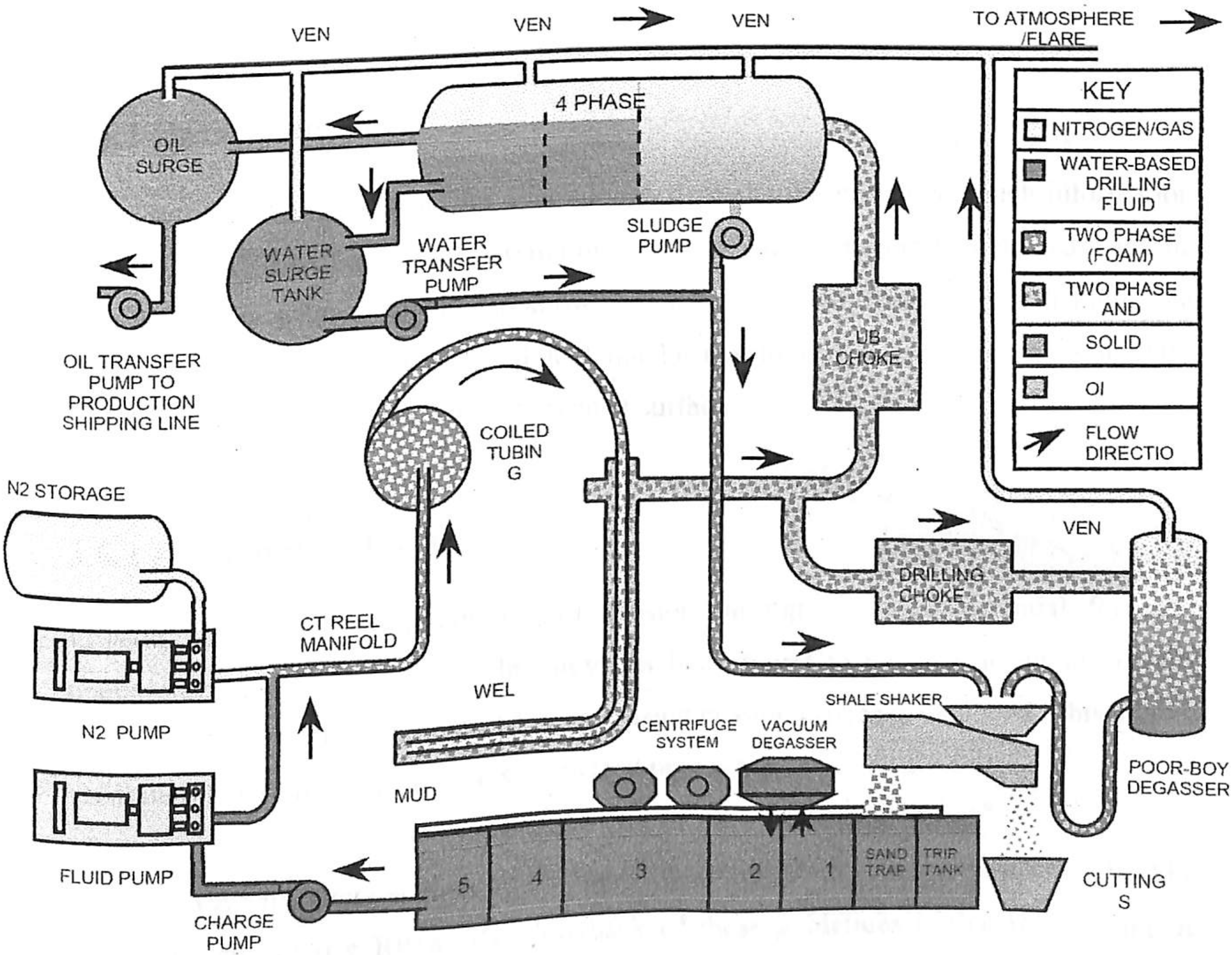
A number of approaches in separation technology have emerged recently.

- Separate the gas first and then deal with fluids and cuttings.
- Separate the solids to minimise erosion and then deal with the gas.

The approach taken is largely dependent on the expected reservoir fluids. It must be recognised that separation technology for underbalanced drilling may have to deal with as many a 5 or 6 phases.

- Drilling Fluid
- Cuttings
- Gas
- Oil
  1. Condensate
  2. Nitrogen

An example of a 4-phase separation system is shown below:



4-Phase Separation System
Fig 3.7

Careful design of the surface separation system is required once the reservoir fluids are known. Dry gas is much simpler to separate as opposed to a heavy crude or a gas condensate reservoir. The separation system must be tailored to reservoir and surface requirements. This requires a high degree of flexibility and the use of a modular system helps to obtain this flexibility.

The use of a modular system for offshore operations is recommended, as lifting capacity of platform and rig cranes is often limited to 15 or 20 Tons. To reduce the total footprint of a separation package, vertical separators are generally used offshore as opposed to the horizontal separators used in onshore operations.

3.6.1 Data acquisition

The data acquisition used on the separation system should provide as much information as possible. This will allow the maximum amount of information to be obtained from the reservoir while drilling. It will also allow for a degree of well testing during drilling. The safety aspect of data acquisition should not be overlooked as well control is directly related to the pressures and flowrates seen at surface.

3.6.2 Erosion monitoring

Erosion monitoring and prediction of erosion on pipe work is essential for safe operations. The use of NDT technology has been found to be insufficient in erosion monitoring. Currently an automated system using erosion probes is deployed. This allows accurate prediction of erosion rates in surface pipe work.

The flow velocity limits applied by the industry to control erosion are defined in the API recommended practice RP14. The drawback of these guidelines is that the amount of solids in production operations is significantly lower then in underbalanced drilling operations. The use of erosion probes has now also allowed prediction of hole cleaning and borehole collapse. As more data is gathered, the behaviour of solids in UBD wells is better understood. Erosion in surface pipe work is still a problem in high rate wells and it is a significant cost of the operation. In general, target 'T's should be used wherever necessary. These should include a method of releasing then quickly for inspection and change-out purposes.

3.7 The Circulation Process

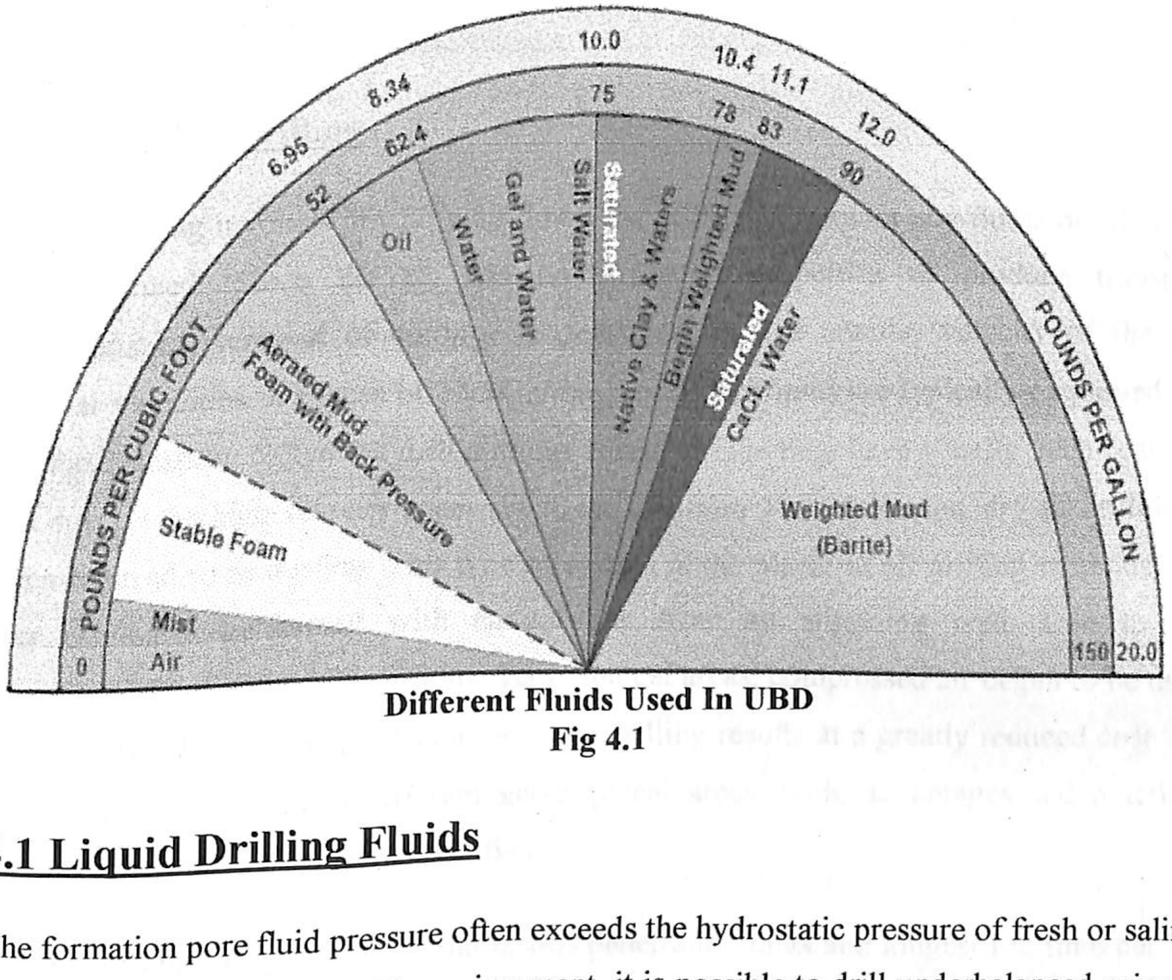
Fluids from the reservoir flow up the wellbore to the surface. The rotating diverter system ensures that the well remains closed. The fluid exits the well through the main flow line into a well test choke manifold. The chokes are normally open and varying the lift gas rate or the liquid rate controls the well. From the choke manifold the flow enters the first stage separator where gas is taken off and the solids are extracted from the fluid flow through a vortex system. The overflow of the first stage separator enters the second stage separator where the fluid is further degassed and any remaining solids are taken out. Drilling fluid is send back to the mud pits. Produced oil is send to a stock tank or to the production train. The drilling fluid is then pumped back down to the well to start the cycle once more.

It is currently normal to have a first and second stage separator offshore. This is mainly to ensure that drilling fluid is degassed before it is send back to the pit system inside the rig. If a gas condensate field is drilled, a third vessel is often required to ensure that condensate is separated. Further advances in separation technology are being investigated to ensure that surface separation packages are smaller and more and more automated.

Chapter 4

4.0 UBD Fluid System

The correct selection of the fluid system used in underbalanced drilling is the key to the successful outcome of an underbalanced drilling operation. We will therefore have a closer look at the fluid systems used in underbalanced drilling.



Different Fluids Used In UBD
Fig 4.1

4.1 Liquid Drilling Fluids

The formation pore fluid pressure often exceeds the hydrostatic pressure of fresh or saline water at the same depth. In this environment, it is possible to drill underbalanced using a liquid. It is not uncommon for conventional drilling operations to become underbalanced, unintentionally, if the wellbore penetrates a region of higher than anticipated pore pressure. Especially shales are known to be overpressured/unconsolidated. In certain circumstances it is possible to achieve underbalanced conditions even though the drilling fluid has a density exceeding the pore pressure gradient. For example, loss of drilling fluid into a low pressure zone can reduce the wellbore pressure, allowing formation fluids to flow into the well from higher up the hole. The inflowing fluids then reduce the drilling fluid density until circulation is regained and mixtures of drilling and formation fluids flows to surface.

4.2 Gaseous Drilling Fluids

This section will refer to the compressed gas phase as air since it is the most economical and widely used gas in reduced pressure drilling. However, other gases may be substituted in each of the systems discussed; Specifics to natural gas or nitrogen being used are discussed separately.

4.2.1 Dry Air Drilling

Dry air drilling involves injecting air down the drillstring without any fluids or additives being utilized. Since the air has no structural properties to produce transport characteristics, removal of cuttings is dependent on the annular velocity of the air. Annular velocities in excess of 1000[m/min] or 3000[ft/min] are typically employed for cuttings transport. When the drill cuttings reach surface they have usually been reduced to a dust by the high velocity contact with the wellbore. For this reason, dry air drilling is often referred to as dusting. This type of system is the oldest of air drilling methods and was originally performed with natural gas from an adjoining well. Due to the unavailability of natural gas in some geographical areas, compressed air began to be used in the early 1950's. This produced the same drilling results at a greatly reduced cost. As this system was tested in different geographical areas, both, advantages and practical limitations of the system were identified.

Dry air drilling systems provide the fastest penetration rates and longest life time per bit of any known drilling fluid. Typically, wells drilled with dry air systems have less deviated holes, better cement jobs, better completions and better production than those drilled with conventional mud systems. Since only air is used in the drilling operation, no contamination or plugging of producing formation occurs. This also greatly reduces the cost per foot of drilled hole when comparing to other drilling methods.

Drilling with dry air systems is restricted by water producing formations, unstable wellbores and high formation pressures. When water saturated formations are encountered, the wet drill cuttings stick together and to the pipe walls and will not be carried from the hole by the air velocity. When these cuttings fill the annulus a mud ring will form which stops the flow of air and the pipe will stick. When water is encountered, an alternate reduced pressure drilling system must be utilized. Since the air does not contain any additives to stabilize well bores or build a wall cake, dry air drilling is not suitable for drilling unstable formations. This problem is typically corrected by utilizing either air mist, stable or stiff foam or aerated fluid.

Most modern compressor and booster systems are capable of producing air pressures to slightly in excess of 1000 [psi] (70 [bar]). When gas or liquid producing formations are encountered with bottomhole pressures approaching this point, air drilling becomes economically unfeasible. Although dry air drilling can be performed in the presence of large natural gas flows, the possibility of downhole explosions and fire are possible if the critical air-methane mixture ratio is reached. This situation typically is not a problem with other types of reduced pressure methods since water is pumped in conjunction with the air.

A set of tables were developed in the late 1950's that calculated air requirements for a typical hole and pipe size. These tables were based on three assumptions: a) the annular velocity of the air is 3000 [ft/min], b) the homogeneous mixture of air and cuttings will exhibit the same flow properties as a perfect gas and c) the geothermal gradient of the formation is applicable as the temperature of the gas. From these early tables, numerous improvements have been made, including the development of sophisticated computer modeling techniques.

4.2.2 Nitrogen Drilling

In underbalanced drilling operations, nitrogen can be used as the drilling fluid, or as a component of the drilling fluid. The major advantage over air is that mixtures of nitrogen and hydrocarbon gases are not flammable. This removes the possibility of downhole fires and stops the possibility of corrosion.

The circulating gas does not have to be pure nitrogen to prevent downhole fires. Mixtures of air, nitrogen and hydrocarbon are not capable of combustion, provided that the oxygen concentration is kept below a critical level. The flammability of natural gas is quite well represented by the flammability of methane. At atmospheric pressure, at least 12.8% oxygen is required before it is possible to create a flammable mixture of oxygen, nitrogen and methane. For minimum oxygen concentrations required for a flammable mixture under prevailing pressure, c.f. section on downhole fire.

4.2.3 Natural Gas Drilling

In underbalanced drilling operations, natural gas can be used (instead of air) as the circulating fluid. Using natural gas will prevent the formation of a flammable gas mixture downhole when a hydrocarbon producing zone is penetrated. Unlike nitrogen, however, natural gas will almost invariably form a combustible mixture when it is released into the atmosphere. This inherently higher potential for surface fires requires few changes in operating procedures from those used in dry air drilling.

4.3 Mist Drilling

Mist drilling is a modification of dry air drilling that is utilized when water producing zones are encountered. Like dry air drilling, this system relies on the annular velocity of the air for cuttings transport out of the hole. In mist drilling, a small quantity of water containing foaming agent is injected into the gas stream at the surface. This produces an air continuous system, with the water mist being carried in the air. Foaming agent concentrations in the water typically range from 0.10% to 0.25% by volume in the water. The foaming agent reduces the interfacial tension of the water and drill cuttings in the hole and allows small water/drill cutting droplets to be dispersed as a fine mist in the returning air stream. This allows the cuttings and water to be removed from the hole without the Formation of mud rings and bit balling.

The air mist drilling system provides comparable penetration and footage per bit rates to dry gas drilling, with the added benefit of being able to handle wet formations. Costs of air mist drilling are slightly higher than those encountered with dry gas drilling since foaming agent and corrosion inhibitor are needed.

- Air is the continuous phase and the liquid consists of discontinuous droplets.
- Fluid or foam injection rates less than 30[bbl/min] or 100[l/min].
- Liquid volume fraction LVF < 0.025.
- Can perform simplified calculations by including water mist as drill cuttings and modify the ROP to account for the equivalent weight being lifted.
- The mist particles travel at a slightly differentvelocity than the air because of slip.

4.4 Foam Drilling

- Foams Rule of thumb to use 30% more air volume compared to air only predictions using Angel's tables and calculations
- Foam moves at the same velocity as the air. Drilled cuttings move at the same velocity as the foam.
- Liquid volume fraction 0.025< LVF < 0.25 @ injection pressure (?).
- Foam can break down when in contact with oil.

4.4.1 Stable Foam Drilling

Stable foam drilling systems are produced by injecting water into the air stream containing 1% to 2% foaming agent by volume @ injection pressure. This concentration of foaming agent, with carefully controlled fluid and air injection rates, produces a viscous foam having a consistency similar to shaving cream. The viscosity of this foam is the primary means for cuttings Transport, as opposed to the annular velocity of the air in dry air and air mist systems. In stable foam drilling systems, annular velocities contribute to reduced hole erosion and large cuttings carried to the surface. Operations employing stable foam drilling systems are capable of effectively removing as much as 500 barrels per hour of down hole fluid influx.

The injection of water into the air stream during stable foam drilling provides a mechanism for introducing other chemical additives. Polymers, clay stabilizers, shale stabilizers, corrosion inhibitors and other needed additives can be used to meet the requirements of each individual well. An adaptation of stable foam drilling was developed by Standard Oil Company of California in the mid 1960's. This system utilized a foam generating unit that mixed the liquid and gaseous phases at the surface. By utilizing this unit, a preformed foam is introduced into the drill pipe at the surface. With conventional stable foam systems, the liquid and gaseous phases are not thoroughly mixed until they reach the bit. Other developments of the Standard Oil preformed foam system included the utilization of polymers to further stabilize the foam.

Since stable foam drilling systems are air internal systems containing high concentrations of foam and water, the potential for a down hole explosion or fire are virtually eliminated. This characteristic, couples with the ability of the system to provide excellent water and cuttings Transport make stable foam systems one of the most versatile of all reduced pressure drilling systems. However, due to the quantities of foaming agent and other additives required, it is also one of the most costly of reduced pressure systems.

4.4.2 Stiff Foam Drilling

Stiff foam drilling systems are an adaptation of stable foam drilling. This system was developed in the early 1960's and gained considerable publicity when utilized to drill 64 inch test holes at the U.S. Atomic Energy Commission's Nevada Test Site in 1963. Stiff foam systems incorporate bentonite and polymers into the stable foam to produce a stable foam with the greater hole stabilizing properties needed when drilling large diameter holes.

The system utilized by the U.S. Atomic Energy Commission consisted of a pre-mixed fluid containing 96% water, 0.3% soda ash, 3.5% bentonite and 0.17% guar gum. A 1% concentration of foaming agent was added to this fluid prior to injection into the air stream. The result was a stable shaving cream type foam with greatly improved hole stabilizing properties. The bentonite provided a wall cake and the guar further improved hole stabilization and cuttings removal. Since that time, other polymers have been found to be more effective than the guar gum, and have also replaced the bentonite in some applications.

4.5 Aerated Fluid Drilling

Aerated fluid drilling is another reduced pressure drilling system utilized primarily to avoid loss of circulation. This method was first employed by Phillips Petroleum Company in 1953 Emory County, Utah. This system is an air internal fluid created by injecting air into a viscosified fluid or mud. The encapsulation of the air in the drilling fluid results in an expansion of the fluid and a reduced density per unit of volume. Cuttings Transport in aerated fluid is dependent on the lifting and carrying properties of the fluid. The sole purpose of the aeration is to lower the weight of the column of fluid on the Formation and reduce the potential for lost circulation without changing the properties of the drilling fluid.

When drilling with aerated fluid systems it should be realized that these are the most corrosive of all reduced pressure drilling methods. However, with proper selection of supply water, proper pH control and the proper utilization of technologically advanced corrosion inhibitors, aerated fluid systems are successfully used world wide.

Aerated fluids are well suited for highly unstable formations where loss of circulation is a concern. Aerated fluids also provide the greatest tolerance to fluid influx of any reduced pressure drilling system.

Costs involved with aerated fluid drilling are primarily related to the composition of the drilling fluid being utilized and corrosion inhibition.

- Any liquid with injected air, N2, natural gas, or CO2
- Liquid is the continuous phase
- Liquid volume fraction (LVF) > 0.25 @ surface

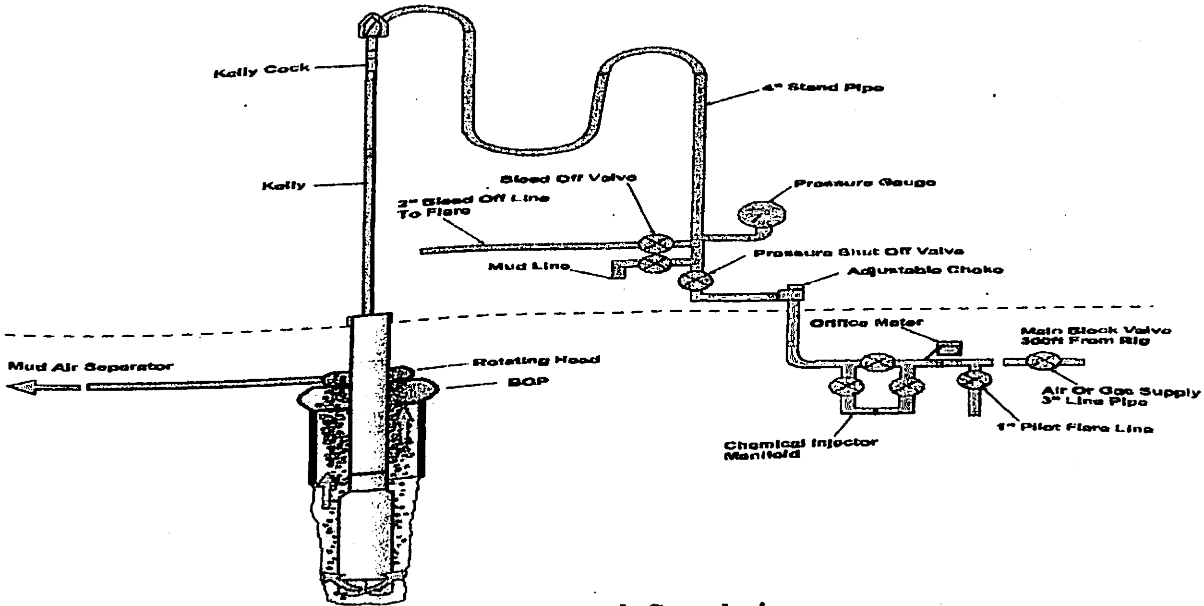
Chapter 5

5.0 UBD Techniques

Next to the situation where plain water is doing the job of an underbalanced drilling fluid, the most common way of going underbalanced and still keep all the advantages of mud (-additives) as higher viscosity and yield strength, is to use a multiphase flow drilling fluid. There are basically two methods for gasifying the drilling fluid and to achieve underbalanced or low pressure situations.

5.1 Gas Injection through Standpipe

The most common method of aeration is to inject gas or multi-phase fluids through the drillstring. The other principle is gas injection through a parasitic string or liner into the annulus. It is also possible to use both techniques in combination. Injection through the drillstring, has the benefit of requiring smaller upper hole and casing sizes and allows the benefit of gas expansion to aid in cuttings transport in horizontal wells. Furthermore, this method requires a lower gas volume for a given underbalanced condition than if the gas is injected part-way up the annulus.



Injection through Stand pipe
Fig 5.1

Beside drawbacks further discussed in this chapter, one negative side effect is corrosion of the internal bore of drillstring components if oxygen is introduced. Other considerations are discussed within the chapters for downhole tools such as motors or MWD's.

5.1.1 Non-Steady-State System

Jointed Pipe underbalanced drilling is influenced by a non-steady-state system and requires specialized drilling procedures, circulating system considerations, specialized equipment, and on-site personnel coordination. The effects of non-steady-state, jointed pipe drilling must be properly managed and controlled to maximize benefits, while remaining cost effective. Standard operating procedures for conventional drilling are modified to accommodate UBD with jointed pipe. For example, precautions must be taken while drilling, not only for safety of personnel but to avoid serious damage to the reservoir. The annular hydrostatic and frictional effects of the system must be controlled to maintain proper and stable underbalanced conditions, hole cleaning efficiency and BHA power requirements. Drillstring connections and tripping with jointed pipe influences bottomhole pressure (BHP) and steps must be taken to quantify and minimize the effects. BHP is affected by many interrelated parameters. Injection liquid and gas types and rates, reservoir fluid inflow performance, well configuration and drillstring movement all influence bottomhole pressure.

5.1.2 Bottomhole Pressure

At the pre-planning phase, gas and/or multiphase flow modeling is required to determine circulation system parameters. Injection fluids must be analyzed in conjunction with reservoir fluids, at a variety of conditions, to determine BHP operating limits. Operating limits are determined prior to execution so that contingency plans for the circulating system are in place. Actual well conditions, reservoir pressure variations, and reservoir inflow performance will determine the optimal circulating system.

Bottomhole pressure is a result of the hydrostatic pressure of the annular fluids plus pressure drops created by friction, plus the inertial pressure of fluid acceleration. Conventional drilling calculations for an equivalent circulating density (ECD) use linear correlation's and can not be applied to gas or multi-phase flow. Multi-phase fluid friction significantly influences BHP and is a complicated function of the specific flow regime. Multi-phase flow in wellbore can have many coexisting flow regimes, therefore a computer model is required.

5.1.3 Connections and Tripping

Drillstring movement and connections influence the circulating system. Computer models are good tools for finding average BHP's during steady-state conditions, but the time between drilling and connections can be insufficient to achieve steady-state circulation. As a result of drillstring movement and connections, the BHP rarely achieves a steady state and fluctuates continuously. In a slug-flow regime, the BHP cycles as slugs are transported up the annulus to the surface. During connection, when injection is stopped, fluid separation results both in the annulus and inside the drillstring. Separation of fluids form liquid slugs. Upon restarting injection and regaining circulation, the annular BHP increases or spikes as a result of the liquid slugs and inertial acceleration of the fluid. Pressure spikes created during a drillstring connection must be minimized, controlled and quantified to maintain proper UB pressure conditions. Separation of fluids is directly related to time; therefore, connection time and shutdown time must be minimized. The liquid slug frequency must also be determined to avoid heading or loading the well during connections. At higher liquid rates, the flow regime changes and slug formation is reduced, but pressure spikes will continue to occur during connections because of separation and inertial acceleration of the fluid.

Surge and Swab pressures created during drillstring movement should be controlled to prevent overbalanced pressure oscillations. Drillstring movement can be beneficial for reducing BHP spikes and regaining circulation after a connection by reducing the inertial force of fluid acceleration and creating swab pressures. An UB well can be tripped without killing the well if the proper precautions are taken and if annular flow is properly directed away from the rig floor. If at any time the well begins to affect crew safety, the situation should be remedied by either killing the well or determining why the flow stream is not being effectively diverted away from the work area.

5.1.4 Making Connections, step by step

The following steps should be taken to make connections:

1. The well should be circulated until the returns are free of cuttings or at least minimized.
2. While circulating the hole clean, reciprocate the pipe slowly to wipe out any potential mud ring that may have started to form.
3. If a downhole motor is used, follow the operating guidelines (c.f. chapter 4.2.2) to prevent damage.
4. Underbalanced fluids should now be diverted down the blooie line and the flow rate from the compressor reduced.
5. Pull the kelly up and set the slips.
6. Open the bleed-off line and allow gas to bleed off.
7. Slowly break the kelly loose and allow any air to be vented from the drillstring.
8. Make up the next joint of drill pipe as normal.
9. Finally, begin lowering the pipe back to bottom and return the flow stream down the drill string. When returns are seen at the blooie line, drilling can be resumed.

A RBOP or rotating head will cause the annular flow to be diverted down the blooie line. Diverting the compressor flow down the blooie line will create a suction effect which will draw the annular flow preferentially down the blooie line. If pressure on the rotating head is near the limit, then consideration should be given to opening the choke to decrease annular pressure while the connection is being made. Another option is to close the annular preventer on the drill pipe after the kelly slips have been set. This will create a double line of protection while the connection is being made. Be sure that any trapped pressure between the annular preventer and the RBOP is properly vented prior to opening the annulus to resume drilling.

Tripping can be considered as a series of connections. However, a major change occurs when the bottomhole assembly arrives at the surface. If the drill collars can pass through the pack-off, then the trip can continue as before. However, if the drill collars are too large to pass through the pack-off, or if stabilizers or some other large OD tools are used, then the diverter pack-off will have to be removed before the remainder of the string can be pulled. By the time the BHA is tripped to the surface, the annulus has most likely been blown down (if the well is not flowing). If this is the case, the trip can continue because there is minimal danger from a kick.

If the well is producing gas or liquids that can be successfully diverted down the flow line or blooie line by the vacuum created with the compressor flow, then the trip can be continued with precautions taken on each connection. If the well can not be controlled, then the annular preventer will need to be closed and a liquid pill pumped into the annulus to create a cushion and stop the annular flow. It is possible that the well will have to be killed.

Once the bit has cleared the blind ram cavity, the blind ram should be closed. The pack-off can be removed after any trapped pressure is bled off and the bit changed.
Stripping the BHA through the annular or ram to ram are also options if killing or loading the well is not desirable.

5.1.5 Open or Closed Annulus

The decision to use open or closed annulus during connections is dependent on the type of underbalanced well being drilled. For a well that is capable to flowing freely under its own reservoir energy, the annulus should remain open to avoid high shut-in surface pressures and unnecessary increases in BHP. The annulus should be shut in for wells with insufficient energy to maintain flow during connections and underpressured wells that produce insignificant volumes of liquid. This reduces annular fluid separation and stores the annular gas phase energy, which assists removal of liquid slugs formed during shut in. For overpressured or high deliverability gas wells the annulus should be shut in to avoid loss of flow controlling liquid and minimize surface surges post connection.

5.1.6 Initiating UB Drilling

There are some common fundamentals to consider before initiating UB drilling such as

- What pressure is expected at each zone along the well?
- Will formation fluids be produced while drilling?
- which fluid or gas and what volumes?

Based on the answers to the above questions, different kind of surface equipment might be selected and thereby determining operational procedures while initiating drilling. In presence of H2S, additional safety considerations are required. However, the following are examples on how to initiate drilling for different fluid types.

Initiate Gas Drilling

To unload an air hole, the cement and cementing shoe should be drilled out with water or mud, and the cuttings need to be circulated out of the hole.

The following successive steps are,

(a) Go in the hole to the bottom of the casing and pump alternate slugs of gas to the pressure limit of the compressors and water (do not use mud) to bring the pressure back down again for further air injection. After the first gas gets around the casing, the pressure will begin to drop as the hole is unloaded.

(b) When most of the water is out of the hole, pump 5 gallons of foaming agent into the pipe and circulate it around the hole. The detergents will bring up a large quantity of water.

(c) Next go to bottom and repeat this process. Light the blooie line or igniter.

(d) Drill a little formation and then pick up the pipe past the tool joint. Continue this process until the well begins producing dust.

(e) If after 2 hours, the well still is not dusted, add 5 gallons of 50% foamer/water mixture and start again with step (c). Or, close the rams and pressure up the hole with air, then open the rams and let the compressed air blow out of the hole. Then start again with step (c).

If the hole is cased, it should dry in several hours depending on the depth. This is why the casing should always be dried first.

In an open hole, the above procedure should work, but it is sometimes necessary to mist for several hours before the mud will clean up. It is difficult to dry an open hole because the rough surface holds mud. As the mud becomes more concentrated, it is more resistant to drying. The more mud washed out of the hole with water, the easier it is to dry the hole.

Another significant problem in drying an open hole is that there may be a small water influx and the hole will never dry satisfactorily. This situation can be puzzling on location and the cause not readily apparent.

Initiate Mist Drilling

The first step prior to mist drilling is to unload the mud out of the hole as with air drilling, but without attempting to dry the hole. The flare burner should be lit or the flare igniter started. The mist pump and gas circulation are begun. About 1[ft] of formation should be drilled and the string picked up past a tool joint. Continue this procedure for at least 5 feet. Go to regular mist drilling if there is no drag on the pick-up after 5 feet. As soon as there are steady returns, indicated by a continuous flow of mist volume or mixture, wait at least 30 minutes before making additional changes. The system must be allowed to stabilize. If too many changes are made too quickly, it is difficult to determine the impact of adjustments.

Misting with water, water and polymers, or mud can follow the above procedures with the added qualification that the volume of the fluid from the well needs to be compared to the volume of the fluid pumped into the well to determine if there is any influx from the wellbore. Influx from the well can be treated with higher gas rates, with more fluid to increase the BHP, or the influx might simply be ignored.

Misting with oil and nitrogen follows the same guidelines except that a closed system and separator are used. Tanks should be filled with liquid to the operating level and pit volumes measured before starting to mist. This approach will allow a more accurate measure of the influx volume. Influxes with oil mist handled the same as with water mist.

Initiate Foam Drilling

Mud should be unloaded from the hole as with air drilling. However, the hole should not be dried. If a separator or mud pits are being used, stop before switching to foam and check the volume levels in the tanks and separator. Check inflow and outflow meters.

The foam pump and compressor are begun. About 1[ft] of formation should be drilled and the string picked up past a tool joint. Continue this procedure for at least 5 feet. Go to regular foam drilling if there is no drag on the pick-up after 5 feet. As soon as there are steady returns, indicated by a continuous flow of foam or a flow with a little puffing, the foam quantities can be adjusted. After any adjustment to the foam volume or mixture, wait at least 30 minutes before making additional changes. The system must be allowed to stabilize. If too many changes are made too quickly, it is difficult to determine the impact of adjustments. If the flow does not stabilize and continues to head, check the following:

- Is there too much gas for the fluid volume? Is the foam pump actually pumping fluid to the standpipe?
- If the foamer is not making foam with the water. Make a pilot check with a jar of rig water and a mixer. This is the most common problem.

- Is there a fluid influx down hole that flattening the foam (water, oil, salt water)?
- Is the foam pump delivering too much water?

It is not uncommon to have a foamer that does not foam well in the actual operating environment. Foaming agents are not universal and some work better than others in particular circumstances. If long-chain polymers are being used, a pilot test should be conducted to determine if they are compatible with the water.

Initiate Aerated Drilling

Displace the hole with the liquid that is to be aerated. Stop and check the surface equipment. Check the volume in the tanks and fill the separator (if used) to operating level. Check the drilling head for leaks and determine whether a new rubber is needed.

Now start fluid and gas circulation. If possible, start the gas slowly so that a very large head will not hit the surface at once. If all gas is added immediately, a big head and volume increase at the surface is expected. Heading is the greatest problem for aerated systems. Increase the fluid velocity, especially with oil and nitrogen, is the best solution. Sometimes this is not practical because of problems with hole stability.

Initiate Flow Drilling

The most important concern with flow drilling is that it is a transition from conventional overbalanced operations. Often it is not convenient to shut down operations and check all the elements from the rotating head trough the separator. Leaking lines under pressure or pressure surges, lines that are not staked down, frozen lines and valves are other common flow drilling problems.

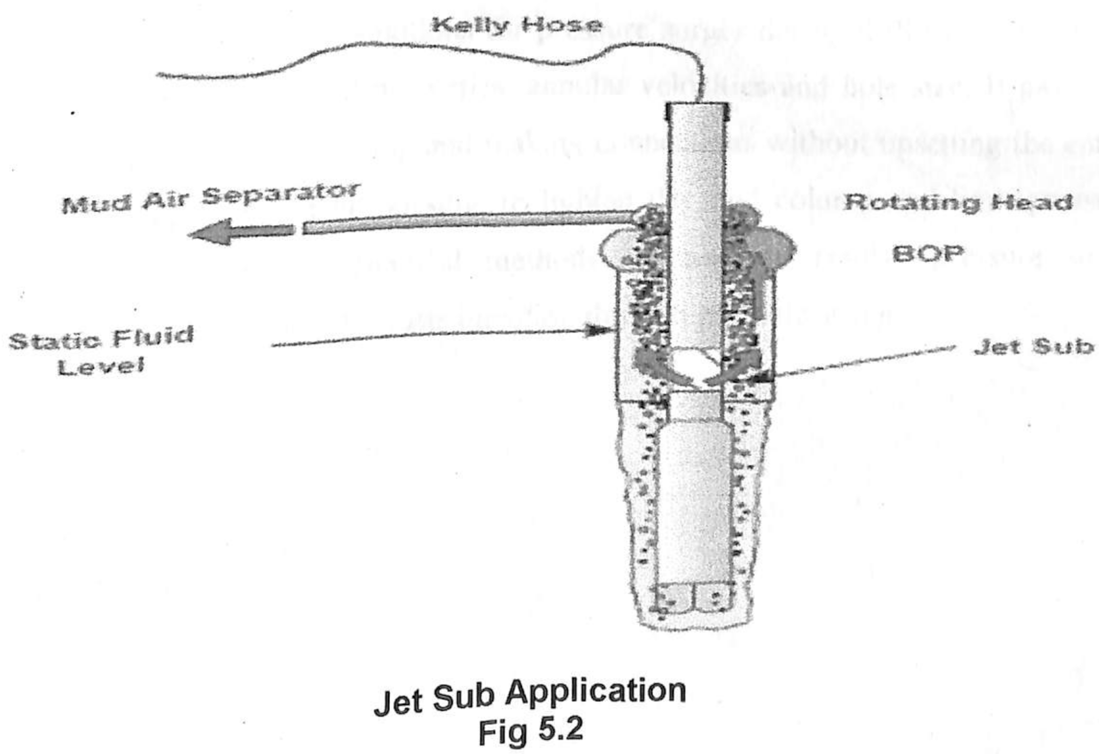
Gas influx while flow drilling tends to unload the hole, and adequate pit volume needs to be available. Modified well-control procedures may be used to limit gas influx until it is clear whether the gas can be flared or whether it needs to be controlled.

Oil influx can cause several problems. Skimming systems that are open pits can release significant amounts of gas to the atmosphere. Mud tanks downstream of the skimming system or a separator are usually gassy. Transition planning often lags behind the drilling conditions and gas concentration can increase on the location very quickly. With oil influx, oil can overwhelm the separation system if the system has not been checked out as operational.

5.1.7 Jet Sub Applications

In areas of lost circulation, or to avoid major pressure surges on trips and connections, a bypass in the drillstring below the fluid level in the hole would preferentially pass gas over fluid and start unloading the upper part of the hole.

An important problem when pumping everything down the drill pipe is that there is a huge volume of non-aerated fluid in the hole. Using air and fluid to unload the hole can cause a major pressure surge. In the case of lost circulation, it might take 1000 bbl of mud lost before returns could be regained. Jet subs ease this problem by unloading from up hole.



Jet Sub Application
Fig 5.2

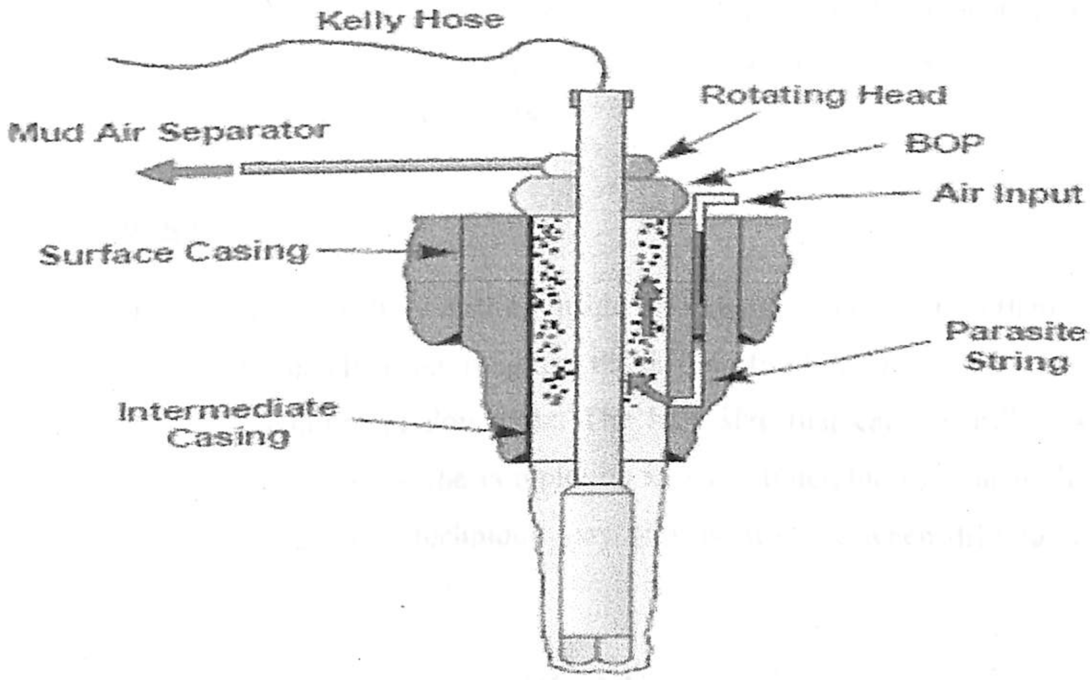
During normal drilling, some of the fluid goes out the jet instead of through the drill bit. The gas phase preferentially exits the jet. Jet subs are normally kept inside the casing.

The complexity of determining the circulating conditions when a bypass sub is run can be extreme. It can be impossible to determine the flow through each component and therefore, making motor performance totally unpredictable.

5.2 Gas Injection through Parasitic String

The primary problem with aerated fluid systems is that they are unstable. In foam, the foaming agent and other additives bind the gas-liquid mixture together. In aerated systems, there is no agent binding the gas-liquid mixture together. In worst case, there will be pressure surges during drilling and during connections and trips. Pressure surges can destabilize the wellbore and cause underbalanced drilling to periodically go overbalanced.

During connections and while tripping, aerated fluids will lose its gas and go flat. There are techniques, such as adding more gas before connections, which help reduce the ensuing pressure surge. Other solutions for pressure surges during drilling, or when the pump is on, are based on fluid properties, annular velocities and hole size. If gas were continuously injected while drilling and making connections without upsetting the entire circulating system, it would be possible to lighten the mud column and limit pressure surges. Most commonly, mechanical methods are used to resolve pressure surge problems. One of those methods is gas injection through parasitic strings.



Injection through Parasite String
Fig 5.3

Compared to gas injection through the standpipe, gas injection through a parasitic string requires higher gas rates and higher gas costs to achieve a given underbalanced pressure. Furthermore, there is additional capital cost associated with injection down a parasite string. The possibility for using this method in a re-entry drilling operation is severely limited, unless existing casing or large bore production tubing can be pulled.

There has to be sufficient clearance between the casing to which a parasite string is attached and both the casing and open hole section inside which it is run, to accommodate the tubing and its injection sub. Mechanical damage is a risk while they are run. There may be particular concern in deviated wells. The injection sub through which they port into the casing can be a weak point in the casing string. The achievable gas injections rates for parasite string applications are higher compared to parasitic liner applications, because the annular volume formed by a parasite liner is large compared to the volume of parasite strings.

However, gas injection through a parasite string or liner provide the advantage that drilling fluid inside of the drillpipe is incompressible allowing efficient operation of mud pulse telemetry MWD's and downhole motors.

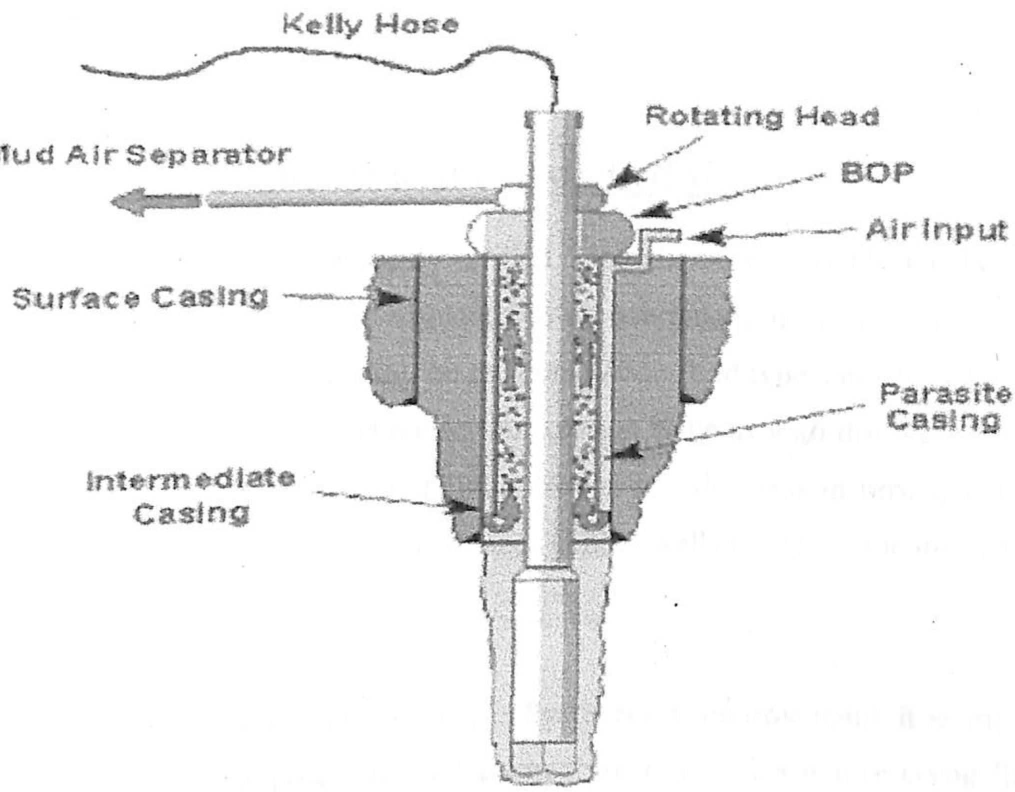
Gas-Lift Systems

It may be possible to deepen a well by drilling inside the existing completion. If there is a gaslift system in place, this can be used to lighten the drilling fluid in the annulus without installing any additional equipment downhole. The hole size that can be drilled will general be severely restricted. Since the completion is also vulnerable to damage by a rotating drillstring, this gasification technique may only be feasible when drilling with coiled tubing.

5.3 Gas Injection through Parasitic Liner

A parasitic liner or dual casing string serves the same basic purpose as the parasite string. If gas were continuously injected during drilling and connections without upsetting the entire circulating system, it should be possible to lighten the mud column and limit pressure surges. If a parasite liner with only a very small annulus were used for gas injection, the inner string could be pulled before setting another string or pipe. This would solve several problems with parasite strings including the need to drill a large hole, equipment fragility, plugging and cementing problems. A dual string can also be set into the curve of a deviated or horizontal well.

The temporary string is run after the casing is cemented. It can be centralized on the bottom or set with a packer and hung off a regular section at the surface. The annulus between the intermediate casing and the parasitic Liner is only used for gas injection; only a very small annular area is required.



Injection through Parasite Liner
Fig 5.4

From an operational standpoint, a second casing string is a common operation and little extra preparation is required. The inner casing string has to be centralized at the bottom of the casing. A simple shoe joint terminus on a pup joint may be adequate. In other situations, a packer may be used to support the inner string. The casing is hung in a regular section hanger bolted to the well head so that it can be removed. A regular wellhead valve, such as would be used for monitoring the annulus, can be used as the air injection point accompanied by a float valve.

The greatest problem with parasite liners is that it reduces the hole size and leaves a step in the hole size after it is pulled. This requires extra preplanning to be able to drill the final hole size. Special slim-hole couplings are required. This method increases casing expense, though with a multiple well program, the string can be reused. Expenses for rig time to run and remove the casing are increased as well.

Chapter 6

6.0 Completing underbalanced drilled wells

The majority of wells previously drilled Underbalanced could not be completed underbalanced. The wells were displaced to an overbalanced kill fluid prior to running the liner or completion. Depending on the completion fluid type some formation will take place. This damage is not as severe for completion brine as with drilling mud due to the removal of the drilled cuttings and fines. However reductions in productivity of 20 to 50% has been encountered in underbalanced drilled wells killed for the installation of the completion.

If the purpose of underbalanced drilling is for reservoir improvement, it is important that the reservoir is never exposed to overbalanced pressure with a non-reservoir fluid. If the well was drilled underbalanced for drilling problems, and productivity improvement is not impaired, then the well can be killed and a conventional completion approach can be taken.

A number of completion methods are available for underbalanced drilled wells.

- Liner and perforation
- Slotted liner
- Sandscreens
- Barefoot

All of the above options can be deployed in underbalanced drilled wells. The use of cemented liners in an underbalanced drilled well is not recommended if the gains in reservoir productivity are to be maintained. Irrespective of the liner type run, the installation process for the completion is exactly the same. It is assumed that a packer type completion is installed. The production packer and tailpipe are normally run and set on drill pipe with an isolation plug installed in the tailpipe. If the well is maintained underbalanced, well pressure will normally require the production packer and tailpipe to be snubbed into the well against well pressure. The use of pressure operated equipment in underbalanced drilled wells is not recommended. A mechanically set production packer should be used.

6.1 Snubbing

With well pressure acting upwards on the completion, the weight of the assembly will be less than the upward force. This means that a snubbing system is required to get the packer assembly in the hole. In an underbalanced drilling system the well can be allowed to flow via the surface separation package. This is an advantage over conventional snubbing operations. As the surface pressure of a flowing well is normally lower than shut in pressure.

At no time during the snubbing operations should the conventional well control BOP stack be compromised. Special snubbing BOP's and a rotating diverter must be used in addition to the conventional drilling BOP's.

6.2 Installation of Solid Liner

Using solid pipe for the liner is no different than snubbing in drillpipe or tubing. The shoe track of the liner must be equipped with non return valves to prevent flow up the inside of the pipe. The liner is normally run with a liner packer and the liner can be snubbed into the live well. Once on bottom the liner hanger and packer are set and the reservoir is now sealed. If zonal isolation is required, ECP's must be run at pre-determined intervals. Once the liner is set the pipe must be perforated to obtain flow. This can be achieved using the normal procedures. It must remembered that any fluid used must maintain the underbalanced status.

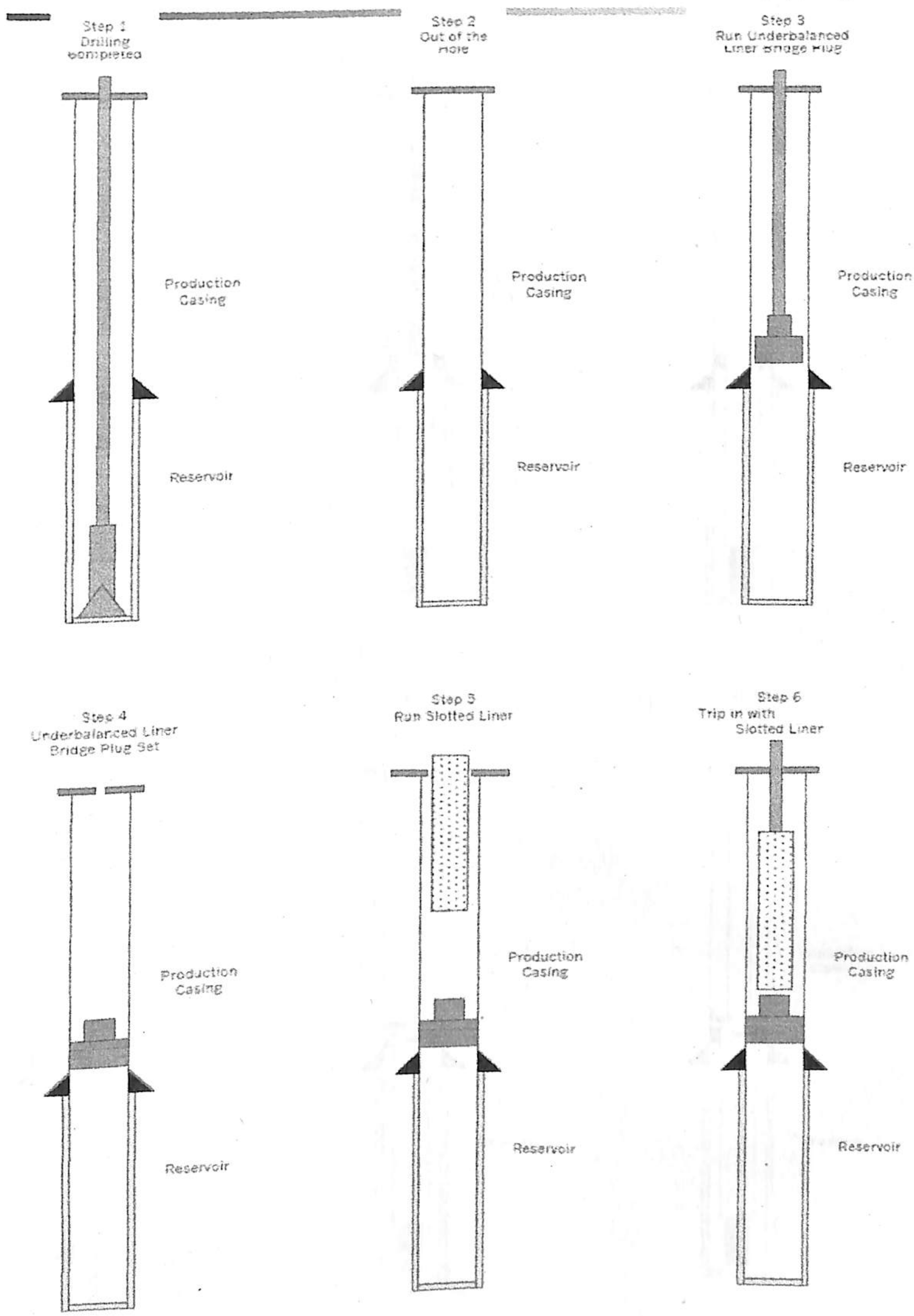
6.3 Installation of a perforated liner or sandscreens

The main disadvantage of running a slotted liner or sandscreens in an underbalanced drilled well is the fact that isolation is not possible across the slotted section of the liner or screen with the BOP's.

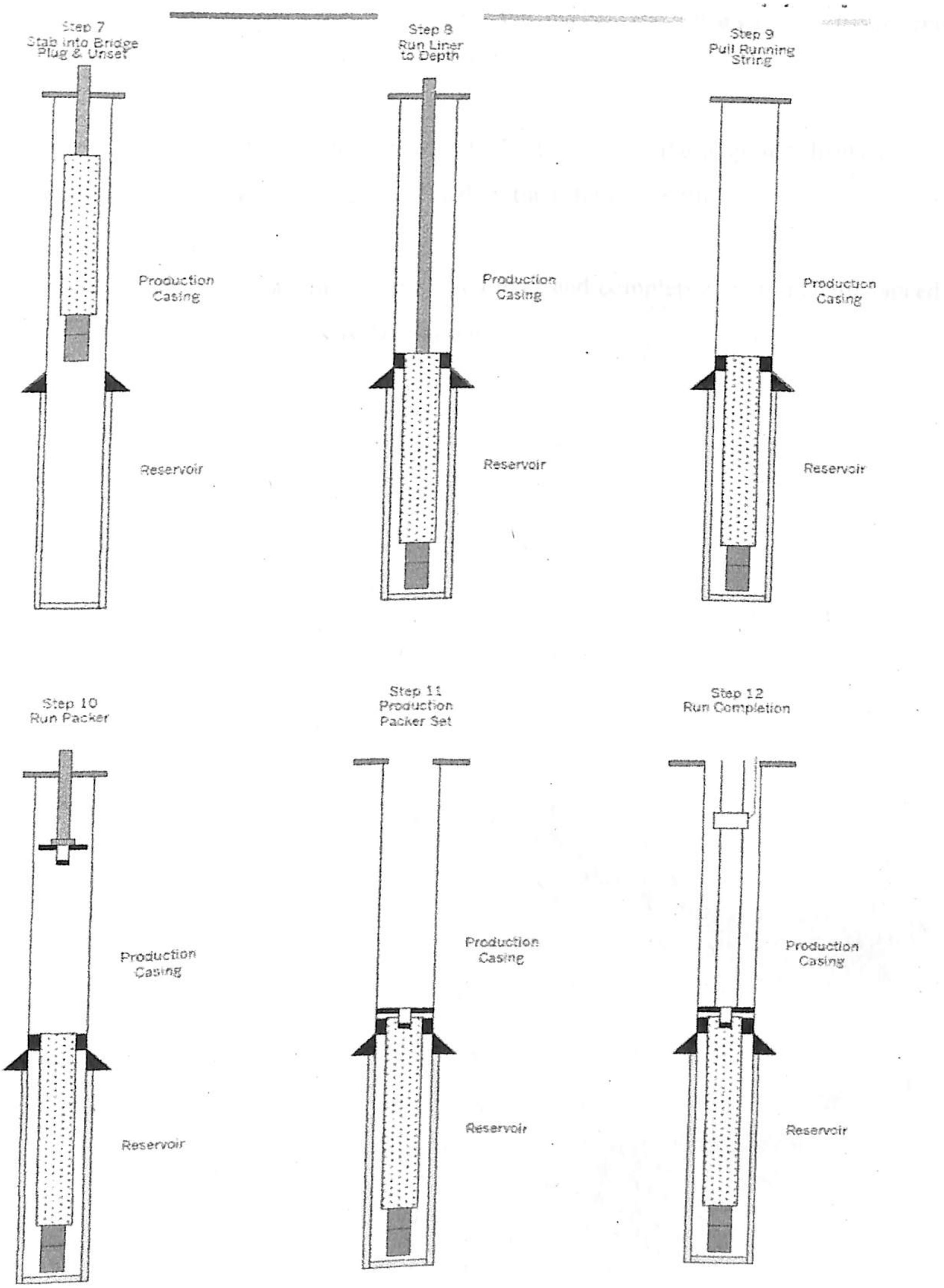
The use of plugged slots that are dissolved once the liner is installed downhole is not deemed safe for offshore operations. The pressure integrity of each slot would have to be tested prior to running each joint and this is not feasible.

The use of special blanking pipe in sand screen also adds complications to the installation procedures. Running a slotted pipe or screen into a live well cannot be done safely. Even if all the holes are plugged the potential for a leak is too great. The only way to install a slotted liner in a live well is by using the well as a long lubricator and by isolating the reservoir downhole.

There are very few mechanical methods of downhole isolation available for the running of a slotted liner. The Baker "Underbalanced Liner Bridge Plug (ULBP) system" is one of the few systems currently on the market. This system allows a retrievable plug to be set in the last casing. This isolation plug is released by a retrieving tool which is attached the bottom of the slotted liner. This retrieving tool unseats the isolation plug. The retrieving tool then swallows the isolation plug or packer. The swallowing action of the retrieval tool ensures that the plug and retrieving tool are rigid and can be run to TD



Installation of liner
Fig 6.1.1



Installation of Liner
Fig 6.1.2

without hanging up in the open hole. Both the packer and retrieval tool have been specifically designed to be released by the liner.

If necessary the well can be lubricated to kill fluid on top of the plug and displaced via the slotted liner when the drill string is sealed by the rotating diverter.

The complete procedure for running of slotted liner and completion in an underbalanced drilled well is outlined in the above 12 diagrams.

6.4 Completion Running

The main problem with running the completion in a live well is the installation of the SSSV control line. Once the control line is connected the BOP's no longer seal around the pipe. Therefore once again the simplest method is to isolate the reservoir prior to running the completion.

In the case of the completion the production packer with a plug installed in the tailpipe is snubbed into the live well and the production packer is set on drill pipe. The packer assembly would be lubricated into the well by utilising the snubbing well control system.

Once the production packer is set the drillpipe can be used to pump completion fluid to provide an additional barrier that can be monitored if required. The completion is now run conventionally. The isolation plug in the tailpipe will be retrieved during the well commissioning. Once again before pulling this plug the fluid should have been displaced out of the completion string. This can be achieved with coiled tubing or with a sliding sleeve.

Once the completion has been installed, the well is ready for production. No clean up or stimulation is required in the case of underbalanced drilled wells.

6.5 Workover of an Underbalanced Drilled well

The workover procedure is a reversal of the completion running, i.e. a suspension plug is installed in the production packer tailpipe and the well is lubricated to kill fluid. After retrieving the completion the packer picking assembly is run to the packer depth and the well is returned to an underbalanced condition prior to retrieving the packer. This ensures that formation damaging kill fluid does not come into contact with the reservoir at any time.

6.6 Underbalanced drilled Multi-Lateral Wells

The setting of the production packer with a mechanical plug allows the lower leg in a multilateral well to be isolated and remain underbalanced whilst the second leg is drilled. After running the liner in the second leg the completion can be run and a second packer can be installed and stabbed into the lower packer. If leg isolation is required a flow sleeve can be installed at the junction to allow selected stimulation or production as required. Re-entry into both legs is also possible utilising a selective system. More detail to the exact requirements from a multilateral system will need to be reviewed.

Drilling a multilateral well underbalanced with the main bore producing can be done but the drawdown on the reservoir will be small. A further setback will be that cleaning up of the lateral is difficult if the main bore is a good producer. Getting sufficient flow through the lateral to lift fluids can be a challenge.

6.6.1 Advantages & Limitations for live well deployment

Listed below are the pros and cons for remaining underbalanced and utilising a mechanical injection system (snubbing) to install downhole barriers. This allows both the slotted liner and the completion to be run without the need to be in an overbalanced mode with kill fluid in contact with the formation.

PROS	CONS
1. Reduced formation damage	1. Additional equipment & interfaces required for snubbing
2. Reduce risk of surface leaks	2. Additional single barriers
3. Possible to run irregular OD completion assemblies	
4. Provides downhole barriers for both the completion & the slotted liner	

Table 6.1

Chapter 7

7.0 Monitoring in Underbalanced Drilling

In underbalanced drilling we have to monitor two parameters

1. Pressure near the bit
2. Hole Diameter

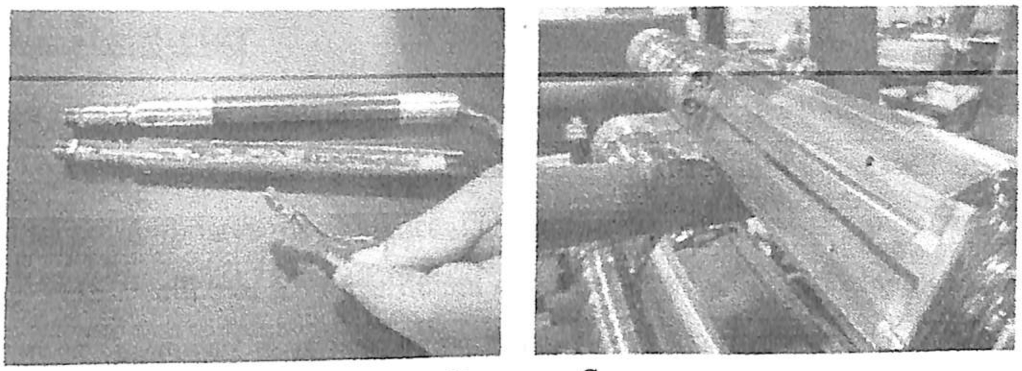
7.1 Pressure near the bit

If we are maintaining pressure in the annulus less than reservoir pressure but if pressure in the annulus near the bit more than reservoir pressure due to influx coming from the reservoir & cutting present in the drilling fluid than it means we are not maintaining underbalanced condition. Due to this increase in ROP by underbalanced drilling doesn't work. So for proper underbalanced drilling operation the pressure in the annulus & pressure near the bit in the annulus must be less than the reservoir pressure.

For monitor pressure in the annulus in underbalanced drilling we generally use pressure measurement LWD tool in BHA.

Pressure Sensor Theory

Downhole pressure sensors are drilling performance tools that provide continuous and direct downhole measurement of absolute bore and annular pressure .Bore pressure communicates with the transducer through a hole on the inside of the insert Annulus pressure communicates with the transducer through a hole on the outside of the collar. Real-time LWD pressure measurements provide information on down hole hydraulics and fluid performance that help the driller avoid drilling problems and optimize the drilling process.



Pressure Sensor
Fig 7.1

Safe Operating Envelope:

For safe drilling the equivalent mud density must remain between

- Minimum Fracture Pressure
- Maximum Pore Pressure

Annulus Pressure

Hydrostatic density of the mud column plus frictional losses in the annulus from the pressure sensor to surface

Bore Pressure

Hydrostatic density of the mud column plus frictional losses through the BHA below the pressure sensor, pressure drop through the bit and frictional pressure losses in the annulus from the bit to the surface

Differential Pressure

Difference in pressure between the bore and annulus pressure gauges. It provides the pressure across the BHA and through the bit and is used to monitor motor performance, blockage at the bit, washout in the lower BHA, and evaluating where packoff is occurring.

7.2 Hole Diameter

Due to less pressure in the annulus than in the reservoir, there is a problem of well integrity in the underbalanced drilling operation. If the formation is not well consolidated than formation will cave in. This caving of the formation will cause struck up of drillstring in the wellbore. So for efficient underbalanced drilling operation the wellbore diameter must be monitor & it must be same as in the well profile.

For monitor the diameter of the wellbore we generally use LWD caliper log or we can also monitor from wireline caliper log survey after a constant interval of time. But this will take more time as we have to remove the whole drillstring outside & than run the wireline tool. So we prefer to work with continuous LWD caliper log.

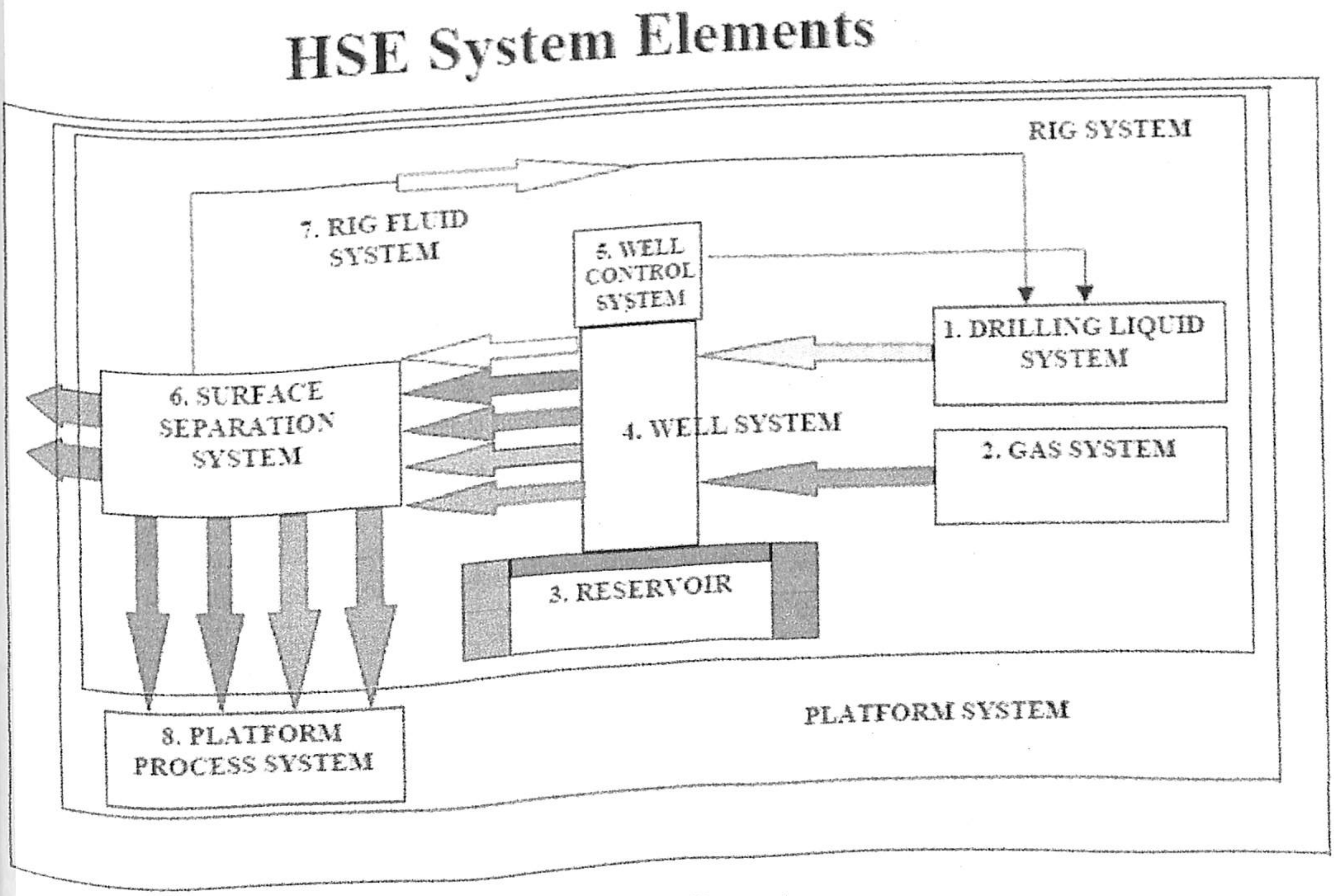
Caliper LWD

A method for determining the diameter of a wellbore, the wellbore being drilled by a drillstring immersed in weighted mud, the weighted mud having a significant weight fraction of a heavy componet. A well logging instrument having a gamma ray source & energy-sensitive gamma ray detectors rotates within the wellbore to define a transient interface with a facing portion of the wellbore wall. The instrument measures Compton-effect gamma ray scattering and photoelectric-effect gamma ray scattering of gamma rays that cross a first interface, and of later gamma rays that cross an opposite interface, at each of a plurality of locations along the wellbore to produce a group of gamma ray counts at each of a series of wellbore locations. The counts are used to determine standoffs, weight fraction and wellbore diameter.

Chapter 8

8.0 Health Safety and Environmental Issues

Because underbalanced drilling involves working on a live well, a Hazard Operational analysis is required on the full process. To this effect a flow chart has been created that shows all the elements in the underbalanced drilling process. Using this diagram, each element can be analysed for input and output. This diagram has been used to good effect to ensure that all items of an underbalanced drilling system are reviewed during the HAZOP. It also allows procedures and documentation to be reviewed for all parts of the underbalanced drilling system.



HSE System Elements
Fig 8.1

8.1 Environmental Aspects

The underbalanced drilling system is a fully enclosed system. When combined with a cuttings injection system and an enclosed mud pit system, a sour reservoir can be drilled safely using an underbalanced drilling system. The pressures and flowrates are kept as low as possible. It is not the intention to drill a reservoir and produce it to its maximum capacity. A well test can be carried out during drilling underbalanced to provide some productivity information.

The hydrocarbons produced during the UBD process can be routed to the platform process plant, export or flared. There is currently work being undertaken to reduce flaring and recover the hydrocarbons for export. In a prolific well a significant amount of gas can be flared during the drilling process. Recovering this gas provides an environmental benefit and an economic benefit. Oil and condensate recovered are normally exported via a stock tank into the process train.

8.2 Safety Aspects

Beside the full HAZOP a significant amount of crew training is required for underbalanced drilling. A drilling crew has been instructed during its entire career that if a well kicks it must be shut in and killed. During underbalanced drilling the single item to be avoided is to kill the well. This may undo all the benefits of underbalanced drilling. Working on a live well is not a normal operation for a drilling crew and good training is required to ensure that accidents are avoided.

The underbalanced drilling process is more complex when compared to conventional drilling operations. Gas injection, surface separation as well as snubbing maybe required on a well. If the hydrocarbons produced are then pumped into the process train, it is clear that drilling is no longer a stand-alone operation.

The reservoir is the driving force in the UBD process. The driller must understand the process and all the interaction required between the reservoir, the liquid pumprate, the gas injection and the separation and process system to safely drill the well. When tripping operations start, the well must remain under control. Snubbing pipe in and out of the hole is not a routine operation and a specialised snubbing crew is normally brought on to snub the pipe in and out of the hole.

The extra equipment also brings a number of extra crew to the rig. So besides a more complex operation a number of service hands are on the rig that now need to start working with the drilling crew. Yet the drilling crew will move back to conventional drilling once the well is completed. The drilling crew will need to be trained in this change of operating.

If a number of wells are to be drilled underbalanced in a field, it maybe an option to consider batch drilling of the reservoir sections. This saves mobilisation and it also sets a routine with the drilling crew. It must be stated that few accidents occur during underbalanced drilling, this is mainly believed to the high emphasis on safety during live well operations.

8.3 Step by Step Approach

It is considered prudent if a number of wells are to be drilled underbalanced with a new crew to apply a step by step approach to underbalanced drilling. The first well is drilled underbalanced but killed on trips. The second well is drilled underbalanced and tripped underbalanced but the well is killed for completions. The third well is drilled and completed underbalanced. This allows all crew and service providers to train and prepare the equipment.

Chapter 9

9.0 Limitations

There are not only advantages to underbalanced drilling. Before embarking on an underbalanced drilling program, the limitations of the process must be reviewed. There are technical limitations as well as safety and economic limitations to the underbalanced drilling process.

Conditions that can adversely affect any underbalanced operation:

- Insufficient formation strength to withstand mechanical stress without collapse.
- Spontaneous imbibition due to incompatibility between the base fluid used in the underbalanced drilling fluid and the rock or reservoir fluid. Use of a non-wetting fluid can prevent or reduce this situation.
- Deep, high pressure, highly permeable wells presently represent a technical boundary due to well control & safety issues.
- Non-continuous underbalanced conditions.
- Excessive formation water.
- High producing zones close to the beginning of the well trajectory will adversely affect the underbalanced conditions along the borehole.
- Wells that require hydrostatic fluid or pressure to kill the well during certain drilling or completion operations.
- Slimhole or drilling conditions that result in a small annulus create high back-pressures due to frictional forces.
- Wells that contain targets that contain significant pressure or lithology variations throughout.

9.1 Technical Limitations

9.1.1 Wellbore stability

Wellbore stability is one of the main limitations of underbalanced drilling. Borehole collapse as a result of rock stresses is one issue to be considered. The other issue is chemical stability, which is seen in shale and claystone formations. Both these issues can have serious implications in underbalanced drilling. Defining maximum drawdown and reviewing chemical compatibility with the proposed drilling fluids is a key issue in the feasibility of underbalanced drilling.

No borehole collapse due to rock mechanics and drawdown has been reported in underbalanced drilled wells.

A well drilled in Spain in 1996 encountered significant hole problems and was side-tracked three times and finally produced through the drillstring as a result of borehole collapse. No further investigations into the causes have been published but it is one of the published examples of well bore stability problems.

9.1.2 Water inflow

Water inflow in a depleted reservoir can cause severe problems in an underbalanced drilled well. If the flow rate is high enough the well will be killed as a result of the water influx. Gas lifting a well that produces water at a high rate is almost impossible. Care must be taken that the water leg in a depleted reservoir is not penetrated when drilling underbalanced.

9.1.3 Directional Drilling equipment

Directional Drilling equipment can have limitations on underbalanced drilling. Hydraulic operated tools can not be used in UBD wells and if a gasified system is used the MWD pulse systems may not work. Certain motors and other directional equipment may be prone to failure as a result of the rubber components becoming impregnated with the gas used. Explosive decompression of rubber components is a consideration to be made when selecting equipment.

The higher Torque and Drag seen in UBD wells (as much as 20%) may also prevent certain trajectories from being drilled underbalanced. The higher torque is caused by the reduced buoyancy combined with the lack of filter cake on the borehole wall. This is a factor that may be of concern in ERD wells.

9.1.4 Unsuitable Reservoir

The reservoir may not be suitable for underbalanced drilling. A highly porous, high permeable reservoir can provide too much inflow at low drawdown. It is important that the perceived benefits of underbalanced drilling are kept in mind when planning for underbalanced operations.

9.2 Safety and Environment

The HSE issues of an underbalanced drilling operation may prove to be too complicated to allow underbalanced drilling to proceed. If a safe system cannot be designed and implemented, underbalanced drilling should be re-considered. A serious accident in underbalanced drilling operations can cause a severe setback in this technology. It can be done safely providing that all issues are addressed.

9.2.1 Surface equipment

The placement of the surface equipment may prove to be impossible on some offshore locations. There can be problems with rigfloor height and with deck space or deck loading. Both the wellhead equipment and the surface separation equipment must be carefully designed to fit the platform or rig.

9.2.2 Training

The entire platform/ rig crew must be trained in underbalanced techniques. Once the crew understands what is to be achieved, operations will run smoother and with fewer problems and accidents. The documentation and policies and procedures should not be forgotten when considering training.

9.2.3 Personnel

The number of crew required for underbalanced drilling is still considered large. 15 to 20 extra crew members are required for full underbalanced drilling and completing. This number must be brought down for safety reasons. Significant work is being undertaken in automation of underbalanced systems to reduce the crew size.

9.3 Economics

The business driver behind the technology must never be forgotten. If the benefits cannot be achieved then the project must be reviewed. Improvements seen from underbalanced drilling are:

- Twice the Penetration rate.
- Triple the Production rate.

Chapter 10

10.0 Case histories

All the below listed underbalanced drilled wells had to be drilled underbalanced, either because of productivity or for reservoir depletion.

Year	Country	Operator	Details
1995	Germany	BEB	Ulsen
		RWE-DEA	Breitburn Gas Storage
	Australia	WAPET	
1996	Denmark	Maersk	Coiled Tubing
	Netherlands	NAM	Coiled Tubing
	UK	Pentex	Oilfield Onshore
1997	UK	Shell	First Offshore Well
	Mexico	Pemex	Offshore well GOM
	Indonesia	Mobil	Arun Gas Field(Depleted)
	Spain	SESA	
	Algeria	Sonarco	
	Oman	PDO	
	Argentina	YPF	
1998	UK	Shell	Offshore Barguer & Clipper
	UK	Edinburgh Oil & Gas	Coiled Tubing Gas Storage Onshore
	Indonesia	Kufpec	Oseil
	Indonesia	Gulf	
	Italy	Agip/SPI	Sicily
1999	UK	Shell	Galleon & Barque
	Sharjah	BP Amoco	

Table 10.1

Chapter 11

11.0 Advantages of Underbalanced drilling

The advantages of underbalanced drilling have been clearly seen during the wells drilled and completed underbalanced. Early wells were killed for trips and this clearly showed the benefits of underbalanced drilled wells. One well was drilled and completed underbalanced and was then stimulated with an acid wash and this once again proved a reduced productivity.

11.1 Drilling Technical Advantages

No mud losses are encountered during underbalanced drilling.

Simple waterbased fluid systems have been used. If torque and drag are an issue, then an oilbased mud system can also be used. Gas solubility in oil needs to be considered when using oilbased mud systems

Penetration rates increase by 2 to 5 fold when drilling underbalanced. This is still a function of formation and bit selection. The amount of drawdown has a direct impact on the rate of penetration.

Bit life is increased. Because the well is drilled faster and the removal of cutting from the bit face is more efficient (Chip Hold down effect)

No differential stuck pipe occurs when drilling underbalanced. There is no wall cake and no over pressure to push the pipe against the wall of the wellbore. It does not mean that no stuck pipe occurs when drilling underbalanced. Key seating and junk as well as hole collapse can still cause stuck pipe even in underbalanced drilled wells.

Inefficient hole cleaning as a result of the multiphase flow can also cause stuck pipe in underbalanced drilled wells.

11.2 Reservoir Technical Advantages

Reduced formation

Reduced formation damage in lower permeability reservoirs leads to an average increase in productivity of 3 times the production seen in overbalanced drilled wells. Although the factor of 3 is now been accepted as an average productivity improvement, significantly larger improvements have been seen on some wells. Once again reservoir studies and knowledge of the damage mechanism will quickly indicate the potential improvements.

Reduced stimulation requirements.

The one well that was drilled underbalanced and then acid washed proved conclusively that acid stimulation does not increase productivity. A well drilled and completed underbalanced will out perform a stimulated well. Saving the costs of hydraulic fracture stimulation often offset the price of underbalanced drilling.

Improved formation evaluation is provided by the ability to test the well while drilling and to steer the well into the most productive zones of the reservoir. Intersection of fractures is possible as a large fracture is recognised by an increase in productivity from the well.

Early Production

Production will start as soon as the reservoir is penetrated. For new field developments this may require the production train to be ready once the first well penetrates the reservoir.

Chapter 12

12.0 Costs

The costs of underbalanced drilling vary greatly with the reservoir encountered and the sophistication required on the surface separation and data acquisition system. The reservoir fluids dictate the required separation equipment and the reservoir pressure dictate the pressure control equipment requirements as well as the gas lift requirements.

The location and the number of wells to be drilled will to a degree dictate mobilisation costs. A detailed feasibility study on a multi-well development will be required while a simple quick look study can be performed on a low pressure land well in Europe.

Comparing a number of operations in Europe, Canada and the middle East we can now provide a ball park figure of 10% of the well cost is the additional cost required for underbalanced drilling. If your well is expensive because of the complex reservoir geometry, it is likely that the underbalanced drilling equipment will also have to be suited to the complex drilling systems required. If a simple vertical well is required in a homogeneous reservoir then the well costs as well as the UBD costs can be low.

If a multi-well development can be drilled successfully underbalanced the reduction in well count could be as high as 25% as a result of the increased productivity. This benefit outweighs the obstacles and cost of underbalanced drilling significantly.

Chapter 13

13.0 Future

The future of underbalanced drilling will see a significant increase in automation and a resulting reduction in crew required.

The use of underbalanced drilling in HPHT reservoirs to avoid or at least increase the narrow pore pressure / fracture pressure window.

The use of underbalanced drilling from floating rigs and with subsea developments. There are currently systems and methods on the drawing board but investment of 2 to 3 million dollars will be required to develop a working system for underbalanced drilling from floating rigs.

Multiphase flow modelling in the annulus and prediction of hole cleaning and cuttings transport will further improve UBD operations.

The use of downhole safety systems will eventually eliminate snubbing systems for UBD wells.

The data acquisition at surface and downhole will improve allowing more and more wells to be drilled underbalanced more effectively.

Better understanding of reservoir damage mechanisms and their associated recovery factors and production profiles will lead to a more selective approach to underbalanced drilling for reservoirs with a real need.

This document provides a flavour of the potential, the drawbacks and the advantages of underbalanced drilling. It is not intended to provide a comprehensive answer to all underbalanced drilling questions. It hope fully provides a guideline and some basic understanding of the technology required for underbalanced drilling.

CONCLUSION

As we know demand of oil & gas increases day by day & we have limited reserves of oil & gas remain in the world. Most of the fields are depleted fields & productions from those fields are not economically feasible if any formation damage will occur. This UBD technique will decrease the chances of formation damage & increase the recovery rate from the field by three times as compared to the overbalanced drilling. This technique also increases the rate of penetration by two times as compared to overbalanced drilling, which will also increase the chances of economically feasible production from depleted fields.

This technology increases the rate of penetration & recovery rate but in this we also need certain equipments other than in overbalanced drilling & trained manpower, so prior to this operation we have to do economic analysis of the underbalanced drilling with the overbalanced drilling. If underbalanced drilling give us more profit than overbalanced drilling by increasing rate of penetration (this will increase the profit by drilling the well in less days) & also by increasing rate of recovery (this will reduce the stimulation cost) than only we apply this technology on fields.

As we know in this technology we maintain annular pressure less than formation pressure, so prior to apply this technology on fields we must know the pressure of the formation that's why we mainly apply this technology in development drilling of the field but not in exploratory drilling.

This technology also very advantageous in case of horizontal drilling because in case of this drilling interaction of drilling fluid with reservoir is more than vertical drilling, so this will reduce the damage of the reservoir with drilling fluid. Now a days almost all of the horizontal drilled by utilizing UBD technology.

All the major companies like British Petroleum, British Gas, Shell, Saudi Aramco (using this technology in world biggest oil field "Ghawar Field" & find lots of advantages & planning to implement this technology in other fields) etc. has accepted this technology & using in their fields & find two times increase in rate of penetration & three times increase in rate of recovery.

Also many of oil field famous services companies like Schlumberger, Baker Hughes Halliburton etc. providing equipments & trained manpower to the E&P companies to utilize this technology efficiently & gives them maximum profit.

Also we know that India import 70% of crude oil & in India we have mainly depleted reservoir left. But production from depleted reservoir not economically feasible by conventional drilling technology. So to produce depleted reservoir we have to utilize UBD technology. But In India till now no UBD well has been drilled, due to increase in demand Indian companies planning to implement this technology.

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