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Abstract

Offshore drilling is one of the most challenging operations in the oil industry, due to the complexity of the operation and the harsh work conditions. Some marine prospects are difficult to drill with the present conventional drilling. Examples of these prospects are the ultra deep water reservoirs and the depleted offshore reservoirs. The reason is that this type of reservoirs is characterized by a narrow drilling window due to the small margin between formation pore and fracture gradients, usually because of the high water column in the first type and the intensive water injection combined with reduction in reservoir pressure caused by the production of reservoir fluids. Therefore a need for developing new drilling methods arose, especially after the recent deep water discoveries in the Golf of Mexico.

Dual gradient drilling (DGD) system started as a joint industry project in 1996, and it has been developed during the last years. DGD is a new non conventional drilling method, and it is classified as a managed pressure drilling technique. This drilling method provides a solution for the drilling issues associated with deepwater and depleted reservoirs drilling. Most of the drilling issues related to conventional drilling are either minimized or eliminated by using the DGD. In DGD operations the well hydrostatic pressure is composed of two fluid gradients, usually seawater (or a low density mud) gradient in the upper part and a heavy mud in the lower part. Although this new system has many advantages, however there are some challenges associated with this system. The system has no proven track as the DGD wells are still few. An additional challenge is the u-tube effect related to mud freefall from the drillstring during circulation stop. This challenge can be prevented by using the drillstring valve, but this one need to be developed to achieve the full efficiency. There are different configurations of DGD system; the most important ones are the Subsea Mudlift Drilling (SMD), the Low Riser Return System (LRRS) and the Riserless Mud Recovery (RMR) system.

The AUSMV (Advection Upstream Splitting Method) scheme has been extended to simulate the dynamics of the SMD system. The AUSMV is a numerical method which is used to analyse two-phase flow in pipes or wells by providing a solution of the conservation equations. Two set of simulations was performed. The first simulation was simple and it aimed to investigate the ability of the AUSMV scheme to handle the SMD system. The results obtained from the first simulation proved clearly the ability of the AUSMV scheme in handling the SMD system.

The purpose of the second simulation was to simulate a SMD kick situation. The well geometry was kept simple, but more realistic data were fed to the AUSMV code. The proposed well was a 2000 m vertical offshore well with 2000 m water depth, a weighted drilling fluid was used, and the kick fluid was gas. The most important extensions done with the AUSMV code were to adjust the boundary conditions to simulate the SMD system. The simulation began with normal drilling, kick detection and occurrence, kick circulation and again normal drilling.

The results obtained from this simulation indicated: the ability of early kick detection when using the SMD, the possibility of controlling the kick situation without using a kill mud since the same mud density was used before and after kick circulation, and the subsea mudlift pump used in the SMD system can function as a conventional choke to control well pressures. Further future simulations can include the use of a more complicated well geometry and using drilling fluids with different densities in kick simulation.

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Ali Mohammed Haj

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Nomenclature

- AUSMV - Advection Upstream Splitting Method
- BHA - Bottom-Hole Assembly
- BHP - Bottom-Hole Pressure
- CDPP - Constant Drill Pipe Pressure
- DGD - Dual Gradient Drilling
- DKD - Dynamic Kill Drilling
- DPDS - Drillpipe Pressure Decline Schedule
- DSV - Drill-String Valve
- ECD - Equivalent Circulation Density
- FCP – Final Circulating Pressure
- FVS - Flux -Vector Splitting
- HAZOP - Hazard and Operability study
- HHP - Hose Hang-off Platform
- IADC - International Association of Drilling Contractors
- ICP - Initial Circulating Pressure
- JIP - Joint Industry Project
- KWM - Kill Weight Mud
- LRRS - Low Riser Return System
- MLP - Mud-Lift Pump
- MPD - Managed Pressure Drilling
- MRL - Mud recovery line
- MW - Mud Weight
- OWM - Original Weight Mud
- RBOP - Rotating Blow-Out Preventer
- RDJ - Riser Dump Joint
- RKB - Rotary Kelly Bushings
- RL - Return Line
- RMR - Riserless Mud Recovery
- ROV - Remotely Operated Vehicle
- SICP - Shut-In Casing Pressure

- SIDPP - Shut-In Drill-Pipe Pressure
- SMD - Subsea Mudlift Drilling
- SMO - Suction module
- SMP - Subsea Mudlift Pumps
- SMS - Subsea Mudlift System
- SPE - The Society of Petroleum Engineers
- SPM - Subsea mud pump module
- SPU - Solids Processing Unit
- SRD - Subsea Rotating Diverter
- SRPM - Subsea Return Pump Module
- SSC - Sub-Sea Choke
- TVD - True Vertical Depth
- VSD - Variable Speed Drive
- WD - Water Depth

1 Introduction

Due to the increasing world demand of energy, the vitality of developing techniques to extract more oil and gas increases, as oil and gas are still the most important energy source. There are many new hydrocarbon discoveries made in deep water environment. Drilling such reservoirs conventionally is challenging and nearly not possible due to the narrow drilling window associated with such reservoirs. Dual Gradient Drilling (DGD) has been developed to provide a solution for these drilling issues.

DGD development started as a joint industry project in 1996 [1,2,3]. Then the system has been developed in the last recent years. The majority of the researches and development of this system has been performed or funded by oil companies. Several papers discussing DGD features and properties have been published. The well tests results obtained from the few field tests have proven that the DGD can provide robust solutions for many drilling issues in deepwater and depleted reservoirs.

Due to the limited but promising data obtained from the field tests of DGD system, this research has been initiated to support the obtained field results by more simulations, as several simulation researches have been performed before. This thesis is aiming to present the DGD and to investigate the dynamics of this system using simulations based on the AUSMV scheme. The thesis will start by a literature review of the DGD system including: the definition, origin and development, dynamics of the system and advantages and challenges related to the DGD system. Then two types of DGD configurations will be described in more details, namely the Subsea Mudlift Drilling (SMD) and the Low Riser Return System (LRRS). An overview of the AUSMV scheme and drift flux model will be presented. Finally the simulation will be performed and the obtained simulation results will be discussed. A more detailed introductory presentation of the literature review done in this thesis is presented below:

1. Dual Gradient Drilling (DGD) Overview:

DGD is an alternative drilling method classified as a managed pressure drilling method. The system is characterized with a hydrostatic pressure composed of two fluid gradients. The system provides a better fit to pore/fracture gradients. There are several types of DGD but all of them utilizes a subsea mudlift pump that transfers mud and cutting from the wellbore to the surface through an external conduct.

DGD has many advantages which include but not limited to: reduced well cost, improved primary cement capabilities and reduction of the number of required casing strings [7]. The system has some challenges that should be mentioned as well: lack of proven track, u-tube effect, new well control procedures are needed, need for topside/rig modifications and drilling crew need to adapt to this new drilling method.

2. The Subsea Mudlift Drilling (SMD):

The system is essentially a Subsea Mudlift System (SMS), due to its utilisations of Subsea Mudlift Pumps (SMP) to extract the mud return to the surface through an external conduit known as Return Line (RL). The RL is connecting the SMP outlet with the mud system on the surface, where the mud return is brought up for further processing. The marine riser is filled with seawater, while a heavy drilling fluid is filling the wellbore. The SMD system controls well pressures by adjusting the SMP rate [20].

3. The Low Riser Return System (LRRS):

The LRRS is categorised as a Subsea Mudlift System (SMS) since it utilises a sub-sea pump to transport the mud return back to the surface through an external pipe (usually called the Return Line (RL)), which connects the outlet device jointed with the marine drilling riser with the mud system on the surface. The system utilizes a centrifugal subsea pump with high capacity. The marine drilling riser is partly filled with drilling fluid, and the rest of the riser is filled with gas at approximately atmospheric pressure The LRRS is utilized by a booster pump on the surface in addition to the main mud pumps, used to fill the riser annulus when needed. This pump is often called fill pump. The LRRS controls well pressures by adjusting both the mud density and the mud level in the marine riser [20].

4. The Drift flux Model

Drift Flux model is based on conservation laws for two phase flow, and it aims to describe the characteristics of the flow. Due to the complications associated with the two phase conservation laws, a third momentum conservation equation is added for the mixture flow (liquid and gas). Furthermore the energy component is eliminated based on the assumption of no significant temperature changes occur within the system (isothermal flow) [21].

5. The AUSMV Scheme:

The AUSMV scheme is an alternative numerical solution to the drift flux model, which is used to analyse the flow of liquid and gas in a well or a pipeline. The AUSMV is the abbreviation of (Advection Upstream Splitting Method). This scheme has been used in the simulations of the SMD system [21].

2 Dual Gradient Drilling

This chapter is meant to be an introductory literature review of the dual gradient drilling (DGD) concept. The chapter includes definition of the concept, drilling issues that can be solved by using DGD, origin and development of this drilling concept, dynamics of the system, and a discussion of some challenges associated with this new method. The definition of the DGD provided in this chapter is taken from the most relevant references, however other definitions can be found.

2.1 Definition

DGD can be simply defined as a drilling method where the hydrostatic pressure of the well is composed of two fluid gradients that maintain the same bottomhole pressure as the one normally achieved with a single fluid gradient [6]. The well pressure is then the sum of a seawater gradient from surface to the mud line and a mud gradient within the well. The mud gradient is referenced to the mud line rather than RKB, and the margin between pore- and fracture pressure gradients is significantly increased. The dual gradient pressure profile is similar to the pressure profile seen in deepwater sediments which is a result of an overburden of seawater and earth. The following equations are used to calculate pressure in conventional drilling and DGD:

Conventional drilling (single gradient):

$$\mathbf{P\ (Pa) = TVD\ (m)\ x\ g\ x\ MW_{single\ gradient}\ (kg/m^3)} \qquad \mathbf{(2.1)}$$

DGD (two gradients):

$$\mathbf{P\ (Pa) = (WD\ (m)\ x\ g\ x\ G_{seawater}\ (kg/m^3)) + [(TVD\ (m) - WD\ (m))\ x\ g\ x\ MW_{dual\ gradient}\ (kg/m^3)]} \qquad \mathbf{(2.2)}$$

Where: P is the well pressure at specific depth, TVD is the true vertical depth to that specific depth, g is the gravity (= 9.81 m/s^2), $MW_{single\ gradient}$ & $MW_{dual\ gradient}$ are the mud densities of the conventional drilling and DGD respectively, WD is water depth and $G_{seawater}$ is seawater density (= 1030 kg/m^3).

In the SPE/IADC paper of Schubert et al [1], dual gradient drilling was defined in more technical details as given in the following:

DGD is one of the Managed Pressure Drilling (MPD) methods. In DGD one uses a pipe with relatively small diameter, often called Return Line (RL) to circulate drilling fluids from wellbore to the mud system on the surface, (Figure 2.1). During the DGD operation, the marine riser is filled with seawater, and a Rotating Blow-Out Preventer, RBOP, is used to avoid mixing the wellbores fluids with the seawater contained in the marine riser.

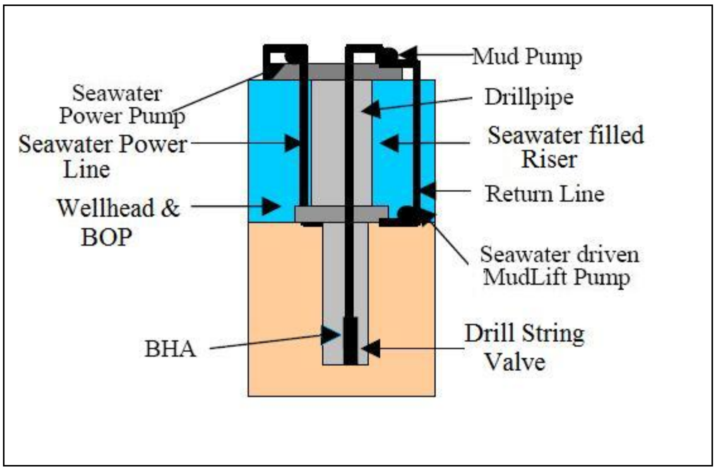

Figure 2.1: Simple Dual Gradient Configuration [2]

The dual gradient effect is then obtained by using a subsea mudlift system. The subsea mudlift system is composed of several subsea pumps situated on the sea floor, with suction/inlet side on the annulus of the wellbore just below the RPOB. The subsea pumps transfer the drilling fluids including cuttings from the wellbore annulus to the mud system on the rig through the RL.

There are three operational options of the subsea pumps: constant inlet pressure, constant circulation rate, or a manual over-ride mode. However the often used option is to obtain constant inlet pressure equal to that of the seawater hydrostatic pressure, which allows use of heavy drilling fluid in the wellbore while still obtaining the same bottom-hole pressure as in conventional riser drilling. The heavy drilling fluid inside the drillstring in addition to maintaining the inlet pressure of the subsea pumps equal to the seawater hydrostatic pressure, causes pressure imbalance in the drillstring and in the annulus below the seafloor. The pressure imbalance causes the mud inside the drillstring to freefall and u-tube. To avoid this problem, the circulation rate of the rig pumps should be higher than the mud freefall rate.

Keeping the inlet pressure at the seawater hydrostatic pressure, and using heavy mud throughout the wellbore, results in a dual gradient effect where the wellbore pressure is kept between the formation pore pressure and the formation fracture pressure over a greater depth interval than for conventional riser drilling. Two to three casing strings can be saved by using DGD [3].

Several configurations of dual gradient system have been developed. The most common are Riserless Mud Recovery (RMR) [4], Subsea Mudlift Drilling (SMD) [6] and Low Riser Return System (LRRS) [10]. SMD and LRRS will be described in details later in this thesis.

RMR system has been developed by AGR Subsea [4], and a Joint Industry Project (JIP) was started in 2000 funded by the Norwegian Research Counsel, Hydro, Statoil and AGR to qualify the RMR system. The RMR system simply enables drilling the top section of the well with engineered mud, and circulating the drill fluid including cuttings to the mud system on the surface. This is achieved by returning the drilling fluid and cuttings from the wellbore through a mud return line which transports the mud from subsea to surface. There is no riser present here. At seabed a suction module and a subsea pump module are used to transport mud and cuttings out of the well, but at the same time avoid spills into the sea. Those advantages are of great importance when drilling top section of subsea wells in deepwater environment.

Advantages of the RMR system can be summarized as such: Improved hole stability, reduced wash outs, improved well control both with regard to shallow gas and shallow water flows, and the avoidance of clay and sand deposits from the boreholes onto the subsea production templates [4]. The main idea behind the RMR system is to obtain the advantages mentioned here. However the dual gradient effect is also achieved, as in the RMR system there is a free/open interface between the mud in the wellbore and the seawater. The dual gradient system is then composed of the seawater column and the mud gradient inside the wellbore. The RMR system is built up from the following seven components (Figure 2.2). Three of these are located subsea and four are surface equipment [5]:

Subsea components

1. Suction module (SMO)
2. Subsea mud pump module (SPM)
3. Mud recovery line (MRL)

Surface components

4. Winch and umbilical
5. Hose hang-off platform (HHP)
6. Control container (two required)
7. Office container

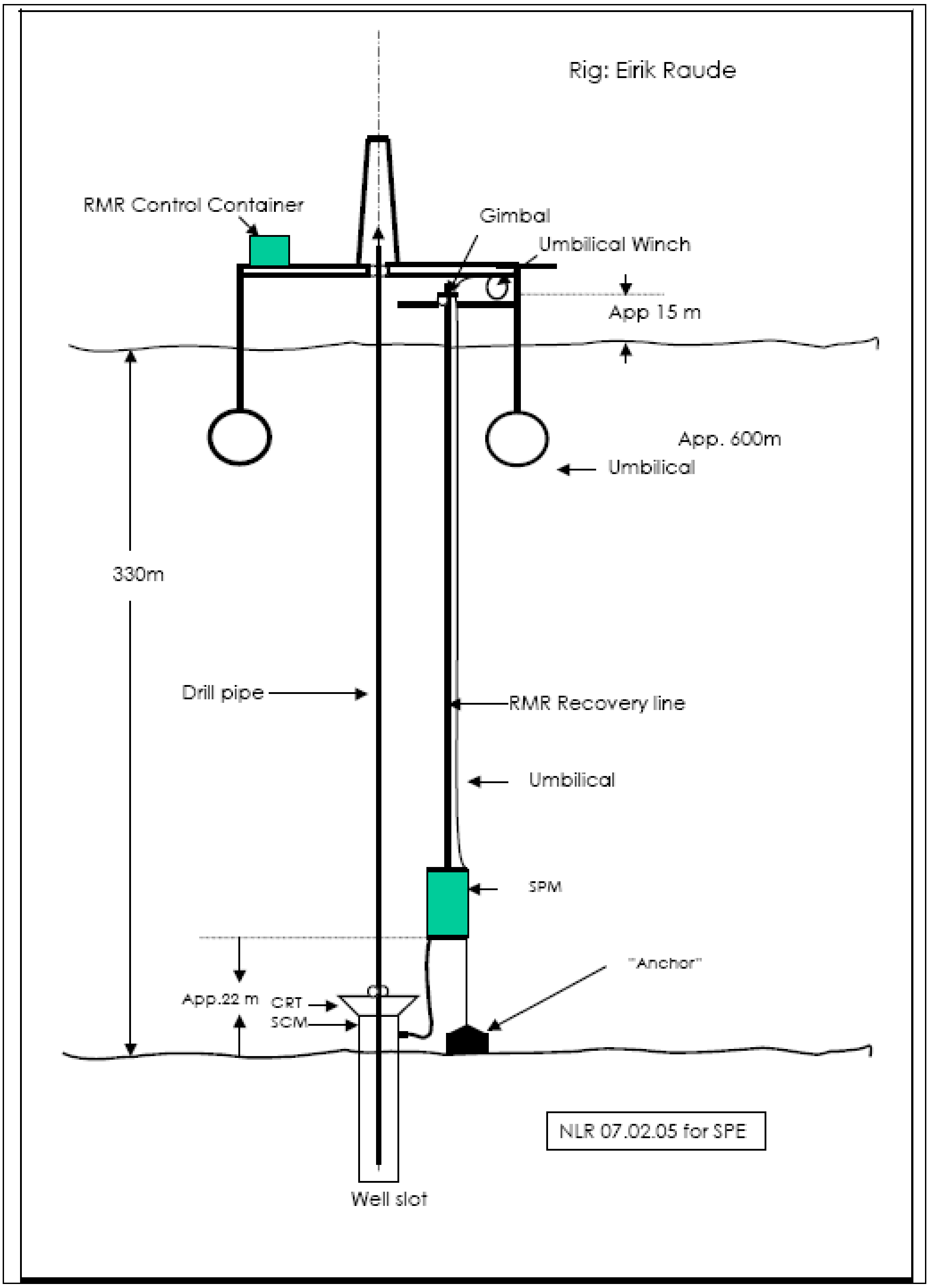

Figure 2.2: The RMR System Schematic [4]

2.2 Advantages of Dual Gradient Drilling

The advantages of DGD can be mainly summarized as follows: reduced well cost, improved primary cement capabilities and reduction of casing sizes [7]. The advantage of reduced well cost will reduce the overall development costs and risks. A successful dual gradient configuration makes it possible to drill wells with fewer casing strings below the surface casing. This means that a larger string can be installed, which is very useful for running equipment such as subsea safety valves, in the completion stage.

The DGD can reduce well cost by over 50% on an ultra-deepwater well through eliminating the rig time used in installing many casing strings. Installation of each casing point takes 4 to 6 days. When using conventional drilling in deepwater wells less than one-third of the rig time is used for actual drilling [7].

An example of drilling issues associated with deepwater wells is [7]: Some operators have been forced to go with a specially designed string of 18” to be run through the 18¾” wellhead to have more pipe options. That is the most drastic example of efforts to squeeze more pipe into a well. The concern for long term production from wells with a minimum cement job has to be weighed against the need to get the well to Target Depth (TD). Minimizing casing strings has the direct impact of saving on rig time and the tangible cost of the pipe, but will also provide improvements in hole size options and better cement jobs. The problem of trapped annular fluids caused when cement from one string is circulated back into the previous string could be reduced if the casing strings were more spaced out.

Reducing drilling cost by using DGD enables operators to drill more exploration wells, and thereby reducing the geologic risks in the early stages of development.

Drilling bit performance studies in deepwater operations showed that a new bit is needed to drill each hole section [8]. Studies proved that DGD enables drilling 1200 to 1500 meters without needing to trip for a bit change, that is possible because less damage occurs to the drilling bit when using DGD.

Schubert et al [1] discussed the advantages of DGD in deepwater drilling by describing the problems related to conventional riser systems, and the solutions provided by using DGD. The main drilling issues associated with conventional riser drilling in water depths greater than 2000 meters, can be summarized in the following points:

- Deck space limitations due to long riser.
- Huge deck loads due to extremely long riser and large mud volumes contained within the riser.
- Problems with station keeping from forces exerted on the riser by ocean currents.
- Cost of mud to fill riser.
- Geologic objectives tend to be deeper below the mud line in deep waters.
- Large number of casing strings required to achieve depth objectives prevents the ability to run large diameter production tubing.

Most of these problems associated with the conventional marine riser are either minimized or eliminated with the use of the dual gradient achieved through the use of the seafloor pumping system.

Some of the advantages of the DGD and the mudlift system are:

- ✓ Less drilling mud required.
- ✓ Better station keeping.
- ✓ Smaller 2nd and 3rd generation floating rigs can be upgraded to drill in deeper water, increasing the rig availability for deepwater drilling.
- ✓ Ability to meet geologic objectives with fewer casing strings, allowing a large enough diameter production tubing to be produced at high rates making the wells much more economical.
- ✓ Reduced drilling time.

2.3 Origin & Development of DGD

2.3.1 History of DGD

The need for the development of a dual gradient drilling system appeared for the first time in the early 1960s [6]. The goal was then to avoid detrimental issues with the riser. The solution was the technology of “Riserless Drilling”. Due to the technological limitations at that time the technology was not successfully developed. In addition to that the conventional riser-based technology was efficient for drilling in the shallow-water discoveries at that time.

In the 1990s, the need for the development of a dual gradient drilling technology arose again, due to the important deepwater discoveries in the Gulf of Mexico [6]. The economical interest and the limited supply of deepwater drilling rigs pushed operators and contractors to find a proper solution to extend the capabilities of shallow water drilling rigs. The dual gradient drilling concept appeared to provide a way to reduce riser weight and station-keeping requirements, as well as mud volumes. This would allow smaller rigs to move into deeper water.

In the beginning of 1996, a representation of deepwater drilling contractors, operators, service companies and a manufacturer discussed potential approaches to "riserless drilling", also known as DGD [6]. The motivation behind that discussion was the potential deepwater discoveries in the Gulf of Mexico, and the well known problems associated with conventional deepwater riser drilling, that can be eliminated or solved by DGD.

The initial workshop resulted in the SMD JIP which has become one of the most important JIPs in the history of the oil industry. The target of this JIP was to deliver a total solution for dual gradient drilling, both the hardware, and the methodology to use that hardware safely and efficiently. After five years and a total cost of approximately 50 million dollars, the JIP had successfully reached that target.

2.3.2 Major DGD Projects

There are many types of DGD configuration such as SMD, LRRS and RMR, and therefore it is not an easy task to track the development of DGD as whole. In this chapter examples of major development projects of the above mentioned DGD systems will be discussed in some detail.

I) Deploying the World’s First Commercial DGD System [9]:

A cooperation project between Chevron, AGR Subsea, Pacific Drilling, GE Oil and Gas, and others is aiming to deploy the world’s first commercial SMD system. The plan was to install the SMD system on a Pacific Drilling Samsung 12,000 Class rig currently being built in Korea. It was expected to begin operations in the Gulf of Mexico in 4th Qtr 2011 (The SPE paper 137319 was issued in 2010).

A full DGD hardware package was added to the drilling rig, in addition to the corresponding processes and concepts to operate the hardware in a proper manner. This has required the simultaneous development of two different, but linked, work streams: hardware and personnel. The “hardware” side of the work has concentrated on the integration of completely new equipment into the rig to make it DGD ready. This includes a subsea pump, a brand new riser, several “riser-specialty” joints and all the rig modifications required to handle, run and support this new drilling system. The “people” work stream included the development of drilling and well-control procedural competence, through coherent planning and the extensive training needed to realize all the benefits of the technology.

This huge task has affected positively the whole Chevron deepwater drilling community. This task required re-examination of the way rigs and drilling assets have historically been deployed. It has resulted in the development of a “Value Driven Drilling Schedule” to optimize utilization of the technology. The SMD system could revolutionise how deepwater wells are drilled and how deepwater assets are explored and developed.

II) Innovation of The Low Riser Return System, LRRS [10]:

The LRRS is a patented method invented recently by Ocean Riser Systems [18]. The LRRS is a method of managing pressure during drilling by adjusting the mud level in the marine riser and returning mud and cuttings to the surface using a subsea pump and a separate conduit. By using this method for managing the height of mud in the riser at any time (level adjustment), the annular and bottom hole pressure can be changed and proactively managed. The system can be used for purely ECD compensation purposes (conventional mud weight) or in combination with a heavier than conventional mud weight and lower static levels in the riser.

III) Gulf of Mexico's First Application of Riserless Mud Recovery, RMR, for Top-hole Drilling [11]:

The first well drilled by using the RMR system was the MC540 Krakatoa, which is located in the Mississippi Canyon area of Gulf of Mexico. Shallow formations of the well are composed of the rapidly deposited sediments from a Paleo Delta. Turbedite sands are often over-pressured and highly permeable, recognized as shallow water flows. Shale formations are soft and unstable, recognized as gumbo.

The target depth was 7620 meter. Due to the 0.36 sg pore pressure ramp-up starting at only 400 meter below mud line and the very challenging shallow formations, drilling the well conventionally was very challenging. The well was decided to be drilled by using a heavy mud after installing the 28" casing. This was to be achieved by using Dynamic Kill Drilling (DKD) or by using an inhibitive water-based mud system and the RMR system. The DKD is a drilling method which employs drilling mud with a density equal to that of kill mud used in well control when a kick occurs. Specifically for the Krakatoa well, the RMR system has provided the following advantages over DKD:

1. **Environmentally:**

RMR would enable re-use of the mud when drilling 26” hole section, resulting in less mud volumes, less transport of mud and less mud discharge to sea.

2. **Improved borehole quality**:

Due to lower volume requirements and lower costs, an inhibitive water-based mud system could be used in the 26” hole section. The engineered inhibitive water-based mud system planned to be used with RMR was expected to stabilize the formations better than the traditional DKD mud, increasing the probability of reaching the planned casing setting depth without remedial work to the wellbore. This potentially also would improve the cement jobs as the hole is expected to be more in gauge.

3. **Well control**:

The kick detection would be significantly improved due to:

- The RMR system enabling real-time monitoring of the seawater/mud interface ("mirror") by means of cameras and sensors at the wellhead.
- Increased return flow, which can be detected immediately by monitoring the subsea pump speed.
- Returns to the surface, enabling volume gain detection in the surface pits.
- Traditional mud logging sensors that can be used for kick detection (gas-out measurements, fingerprinting connections, etc.).

4. **Improved evaluation**:

Cuttings samples can be taken in a hole section where traditionally cuttings are not collected.

The benefits were obvious:

- RMR would improve the borehole stability in this challenging environment and give better well control in an area where shallow hazards are abundant.
- Total cost savings could be documented for riserless mud returns due to substantially reduced mud volumes and logistic cost savings.
- In addition, the operator would make an important step in qualifying a tool for mitigating shallow hazards and reducing the total number of casing strings in the Gulf of Mexico.

2.4 Dynamics of the System

The most important advantage of DGD is that it provides a hydrostatic gradient in the wellbore that fits better between the pore and the fracture gradient. This is especially important in deepwater environment or in depleted reservoirs, where the margin between pore and fracture pressure is very narrow. Drilling conventionally in such conditions is very risky due the well control issues and the completion complications in later stages.

In order to have better idea about the dynamics of dual gradient system, it is important to study the dynamics of the conventional drilling. Wellbore pressure in conventional drilling depends mainly on pre-adjusted mud weight [12]. The mud weight is decided based on formation pressure and wellbore-stability condition, so that the well is in an overbalanced condition when no drilling-fluid circulation takes place. Increasing the hydrostatic pressure by increasing the mud weight can be a time-consuming and costly process that requires adding chemicals and weighting materials to the whole drilling mud volume.

The other solution for maintaining the wellbore pressure as required is by using friction pressure control. This can be obtained by higher circulation rate that generates higher annular friction pressure resulting in higher pressure in the wellbore. This means that a change in the pump rate will cause a rapid change in the Bottom-Hole Pressure (BHP). The disadvantage of this method is that control is lost when drilling-fluid circulation is stopped.

The subsea mudlift system in DGD has three operational options to achieve the required wellbore pressure [1]: constant inlet pressure, constant circulation rate, or a manual over-ride mode. The most common operational mode is to maintain constant inlet pressure nearly equal to the seawater hydrostatic pressure, and a higher-density drilling fluid is circulated throughout the wellbore to maintain the same bottom-hole pressure as in a conventional riser drilling, resulting in the dual-pressure gradients. In other words the hydrostatic bottom-hole pressure is the sum of the seawater gradient from surface to sea floor and the dual gradient mud throughout the wellbore. Figure 2.3 illustrates the difference between hydrostatic pressure in DGD and conventional drilling.

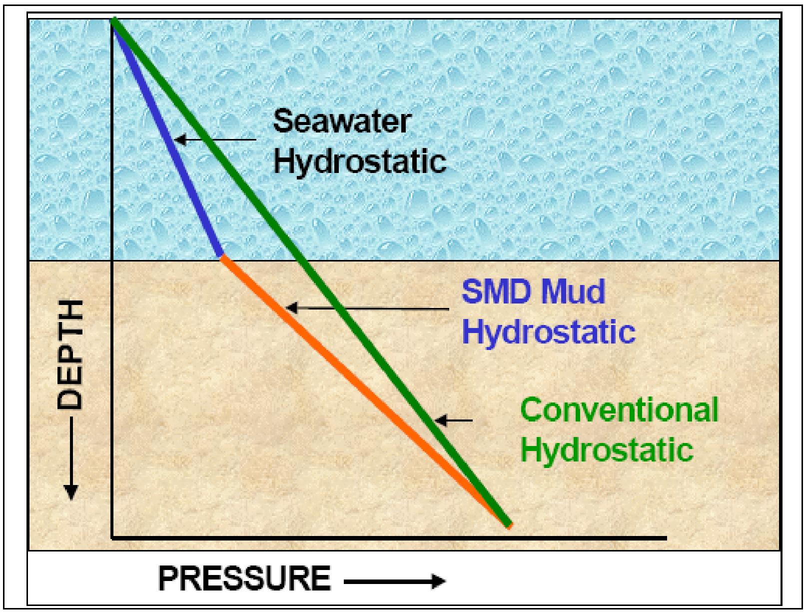

Figure 2.3: Comparison between SMD (DGD) & Conventional Hydrostatic [1].

The dual-pressure gradients in the annulus cause the wellbore pressure to remain in the window between the formation pore pressure and the formation fracture pressure over a greater depth interval than for conventional riser drilling. This effectively widens the window between pore pressure and fracture pressure reducing the risk of kicks and lost circulation in ultra deep waters. It is the ability to manipulate the inlet pressure of the subsea pump that makes DGD possible, and is the key factor in successful well control by managing annular and bottom-hole pressures.

To have a deeper understanding of the dynamics of DGD system, two examples of well dynamics will be presented in chapters 2.4.1 & 2.4.2. The first example is presenting the dynamics of the SMD system while the second one is presenting the dynamics of LRRS. The parameters used in calculation are meant to be as a simulation for real well situation.

2.4.1 Example of the SMD Dynamics

The sample well has the following parameters:

- Water Depth = 1500 m
- Total Depth = 6300 m TVD
- The mud weight of the DG system is variable and can be adjusted.
- DG pressure is to be calculated depending on the selected mud weight.
- Pore pressure, fracture pressure and mud weight for the conventional drilling case are as follows:

Depth [m TVD]	Pore Pressure [sg]	Fracture Pressure [sg]	Conventional Mud Weight [sg]
1500	1,03	1,07	1,05
1700	1,05	1,20	1,05
1900	1,09	1,32	1,15
2100	1,11	1,47	1,15
2300	1,13	1,55	1,42
2500	1,28	1,60	1,42
2700	1,31	1,63	1,42
2900	1,34	1,67	1,42
3100	1,38	1,70	1,42
3300	1,39	1,74	1,42
3500	1,43	1,77	1,68
3700	1,47	1,80	1,68
3900	1,49	1,83	1,68
4100	1,55	1,85	1,68
4300	1,57	1,87	1,68
4500	1,60	1,89	1,68
4700	1,62	1,91	1,68
4900	1,64	1,93	1,68
5100	1,69	1,95	1,87
5300	1,72	1,97	1,87
5500	1,74	1,99	1,87
5700	1,76	2,00	1,87
5900	1,78	2,01	1,87
6100	1,79	2,02	1,87
6300	1,80	2,03	1,87

Table 2.1: Test well parameters for the SMD pressure calculations [13].

The SMD system depends mainly on the mud weight to maintain the well pressure that gives the best fit to pore/ fracture gradients, if all other parameters are kept constant [13]. Figure 2.4 shows that a new casing string is needed at approximately 3800 m TVD when using dual gradient system with mud weight equal to 1.8 sg.

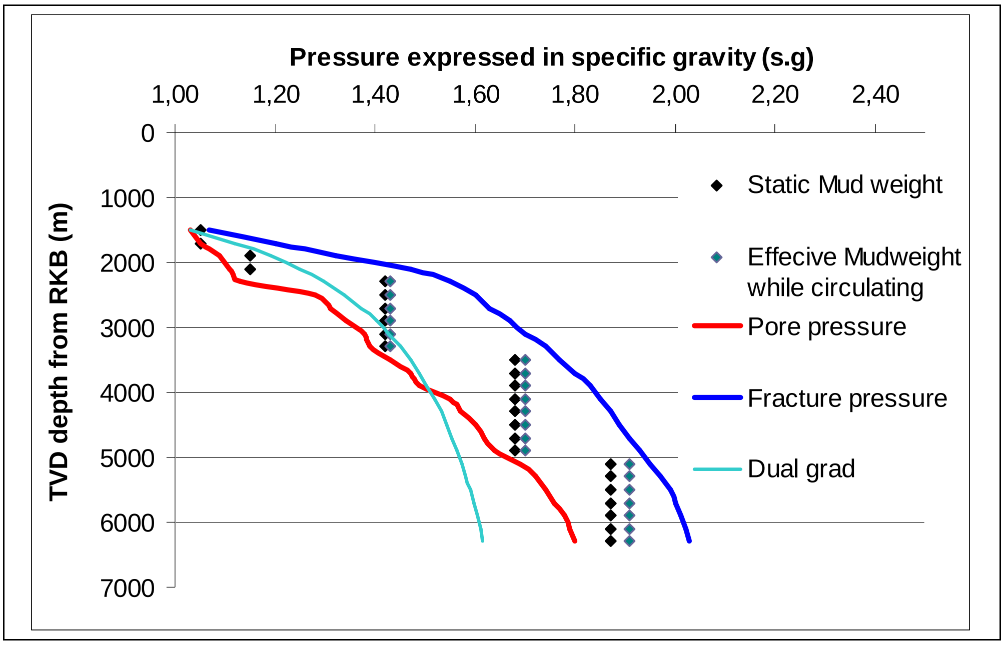

Figure 2.4: Pressure regimes in sample well showing both DG and conventional hydrostatic pressures (With dual gradient mud weight equal to 1.8 sg) [13].

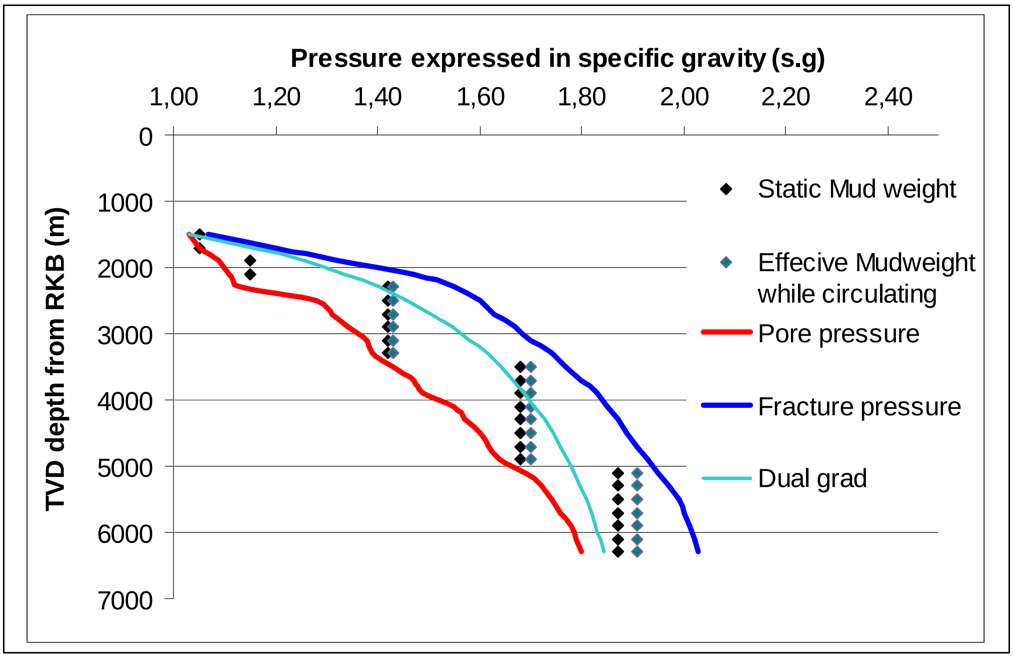

Figure 2.5: Pressure regimes in sample well showing both DG and conventional hydrostatic pressures (With dual gradient mud weight equal to 2.1 sg) [13].

In Figure 2.5 a dual gradient curve that fits much better to the pore/fracture gradient is shown. In this case only the dual gradient mud weight is adjusted to 2.1, while keeping all other parameters as before. This proves that the weight of the mud used in dual gradient is a very important factor. The dual gradient curve shown above indicates that after setting the surface casing, it is possible to drill to target depth without needing to set a new casing. This will save two casing strings. An additional observation is that when getting deeper in the well, the dual gradient curve will become more and more vertical and would in the end converge towards 2.1 sg as the seawater would present a smaller and smaller part of the total pressure [13].

2.4.2 Example of the LRRS Dynamics

LRRS is a DGD method that controls and manages the well pressures. The required well pressure can be obtained by adjusting two parameters: mud weight and the annulus/riser mud level. The LRRS can be used in wells with challenging pressure regimes, such as [10]:

- High pressure combined with a narrow drilling window in deep and medium-to-deep waters. For such cases a heavier mud combined with a low mud level will give a better fit to the drilling window. The benefit is also useful for shallow waters if there are shallow hazards such as shallow gas, shallow water flow, or mud volcanoes.

- High Equivalent Circulation Density (ECD) combined with narrow drilling window. In sections with narrow margins the increased ECD can be compensated by lowering the mud level. This is the case, both for and during, drilling and cementing. Surge and swab related to tripping can also be accounted for. A typical example is highly depleted reservoirs.

- Low formation pressures. Reducing the total static head by lowering the level can allow the use of a better drilling mud that might be too heavy for conventional drilling.

- Uncertain formation pressure and strength or drilling of salt sections.

The LRRS is invented by Ocean Riser Systems. The company has designed two versions of the system, LRRS Light and LRRS Heavy [10]:

1. LRRS Light is used for ECD compensation and improved kick loss detection. It uses conventional well control procedures, and requires minimal incremental rig integration.

2. LRRS Heavy, on the other hand, uses a heavier than conventional mud, which would in most cases fracture the formation if the mud level were to be brought to surface. This system is dependent on the LRRS well control procedures [14], including a subsea drilling choke with some additional equipment and implementation of appropriate well control training.

The Subsea Return Pump Module (SRPM) is an important element of the LRRS, and it is connected to a modified riser joint via a suction hose. The LRRS Control System operates the SRPM controlled by a Variable Speed Drive (VSD) located on the rig.

The required mud level in the riser is maintained by automatically controlled pumps. A nitrogen cleaning system ensures that there are no explosive gas mixtures in the partially-evacuated riser. A wiper element is installed above the diverter element and the evacuated riser is close to atmospheric pressure.

The pump module is launched by a launch and retrieval system over the side of the rig or through the secondary moonpool on dual activity rigs. An option for running the pumps on the riser also exists. The modified riser joints are installed like normal riser joints. The pump suction hose can be connected to the riser outlet using a Remotely Operated Vehicle (ROV).

An example of a test well will be presented to illustrate the LRRS dynamics. The following parameters are used in the sample well [13]:

- Water Depth = 1500 m
- Total Depth = 6300 m TVD
- The mud weight and the mud level of this DG system are variable and can be adjusted.
- DG pressure is to be calculated depending on the selected mud weight and mud level in the riser.
- Pore pressure, fracture pressure and mud weight for the conventional drilling case are as follows:

Depth [m TVD]	Pore Pressure [sg]	Fracture Pressure [sg]	Conventional Mud Weight [sg]
1500	1,03	1,07	1,05
1700	1,05	1,20	1,05
1900	1,09	1,32	1,15
2100	1,11	1,47	1,15
2300	1,13	1,55	1,42
2500	1,28	1,60	1,42
2700	1,31	1,63	1,42
2900	1,34	1,67	1,42
3100	1,38	1,70	1,42
3300	1,39	1,74	1,42
3500	1,43	1,77	1,68
3700	1,47	1,80	1,68
3900	1,49	1,83	1,68
4100	1,55	1,85	1,68
4300	1,57	1,87	1,68
4500	1,60	1,89	1,68
4700	1,62	1,91	1,68
4900	1,64	1,93	1,68
5100	1,69	1,95	1,87
5300	1,72	1,97	1,87
5500	1,74	1,99	1,87
5700	1,76	2,00	1,87
5900	1,78	2,01	1,87
6100	1,79	2,02	1,87
6300	1,80	2,03	1,87

Table 2.2: Test well parameters for the LRRS pressure calculations [13].

Figure 2.6 shown below illustrates that by using a mud weight equals to 1.5 sg and a mud level in the riser equals to 600 m, the dual gradient curve is totally out of the drilling window. This is not acceptable unless the purpose was to drill underbalanced. That will allow production of reservoir fluid while drilling. In Figure 2.7 a mud weight of 2.0 sg and a mud level of 800 meter were used. This combination of mud weight/level gave much better fit to the pore/fracture gradients. In this case drilling can proceed to approximately 5000 m TVD before a new casing is needed. By performing several simulations, the optimal combination of mud weight/level can be found.

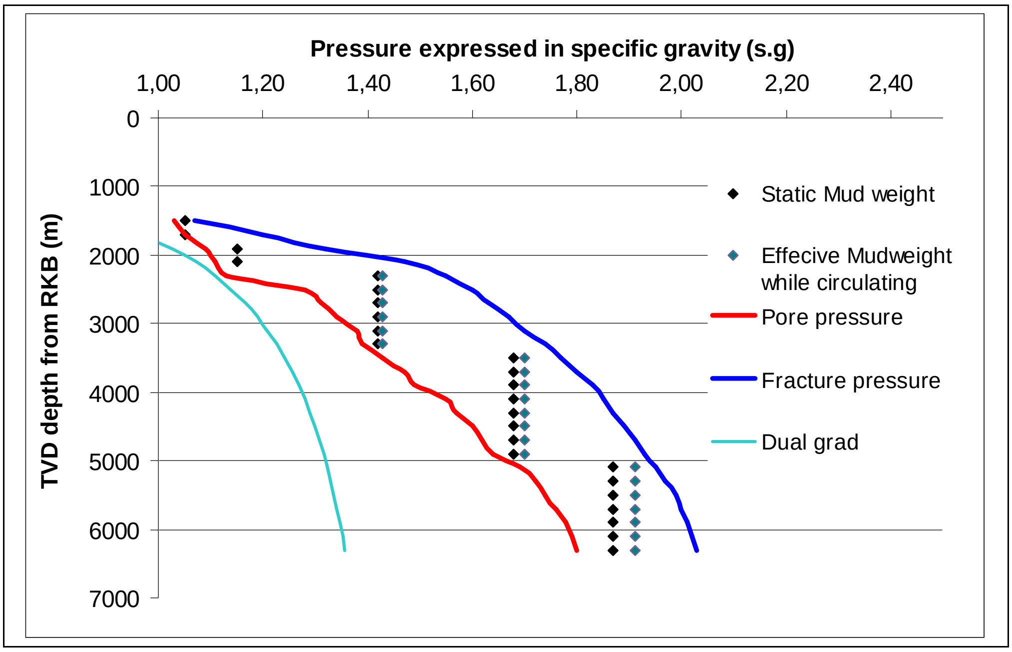

Figure 2.6: Pressure regimes in sample well showing both DG and conventional hydrostatic pressures (With dual gradient mud weight equal to 1.5 sg and mud level equal to 600 m) [13].

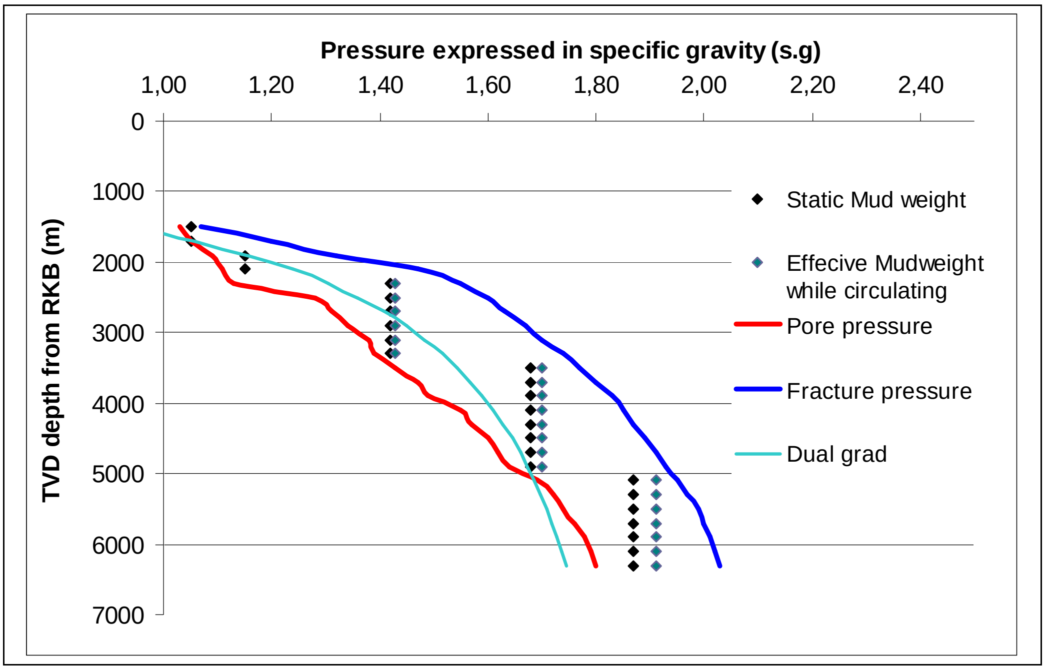

Figure 2.7: Pressure regimes in sample well showing both DG and conventional hydrostatic pressures (With dual gradient mud weight equal to 2.0 sg and mud level equal to 800 m) [13].

2.5 Challenges of DGD

2.5.1 Limited Use of DGD

As DGD minimizes or eliminates many of the problems associated with conventional riser drilling, the limited use of DGD makes it difficult to adapt to this new drilling method. There has been only one recorded dual gradient well drilled to date (the SPE paper 79880 was issued in 2003) [1], resulting in limited experience of personnel utilizing these systems. Since DGD has had only limited use, procedures and equipment developed have had limited proof of reliability and viability.

2.5.2 U-tube Effect

One of the challenges that should be accounted for in DGD is the u-tube effect. This is a phenomenon which occurs in association with the pressure imbalance in the drillstring. In DGD operations a heavy mud is usually used. The heavy mud inside the drillstring in addition to maintaining the pressure on the top of the wellbore equal to the seawater hydrostatic pressure causes pressure imbalance in the drillstring and in the annulus below the seafloor. The pressure imbalance leads the mud inside the drillstring to freefall and u-tube. To avoid this problem, the circulation rate of the rig pumps should be higher than the mud freefall rate [1].

Extensive studies of the u-tube phenomenon have been performed [15]. The results of these studies lead to the conclusion that several factors affect the free-fall rate during the u-tube. These factors include water depth, mud density, well depth, mud viscosity, drillstring diameter, nozzle size, and other restrictions. Water depth and mud density are the two factors that affect the static level of the mud in the drillstring. Freefall rate, static level, and drillpipe size control the time to reach equilibrium. These studies show that freefall rates for ultradeep water (up to 10,000 ft) with drill pipe inside diameters in excess of 5”, and mud weights up to 15.5 ppg, can result in freefall rates of 500 gallons per minute, and it could take over 20 minutes for equilibrium to occur (Figure 2.8 & Figure 2.9).

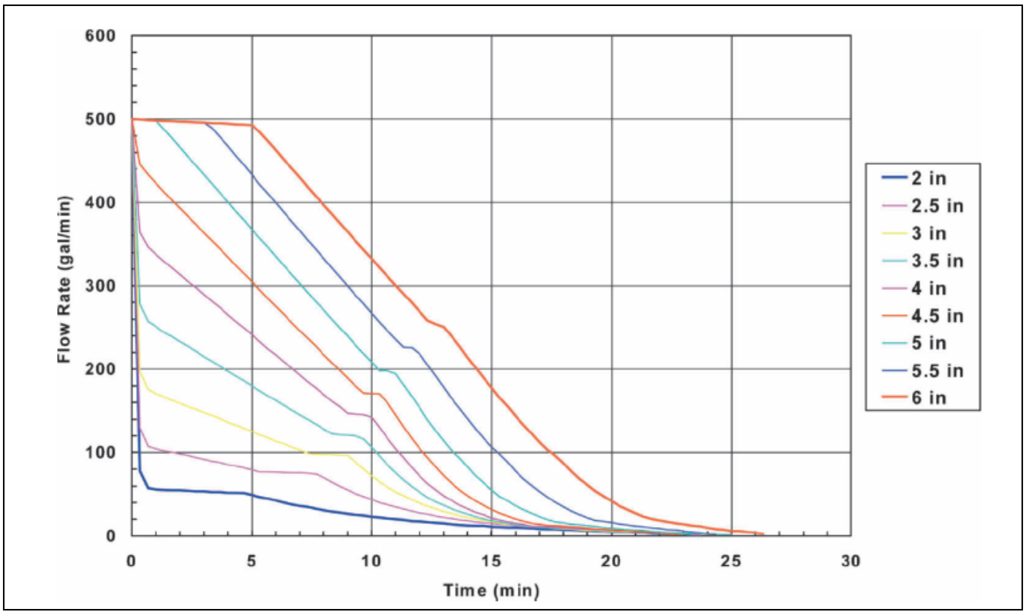

Figure 2.8: U-tube rate as a function of time for various drillpipe sizes [16].

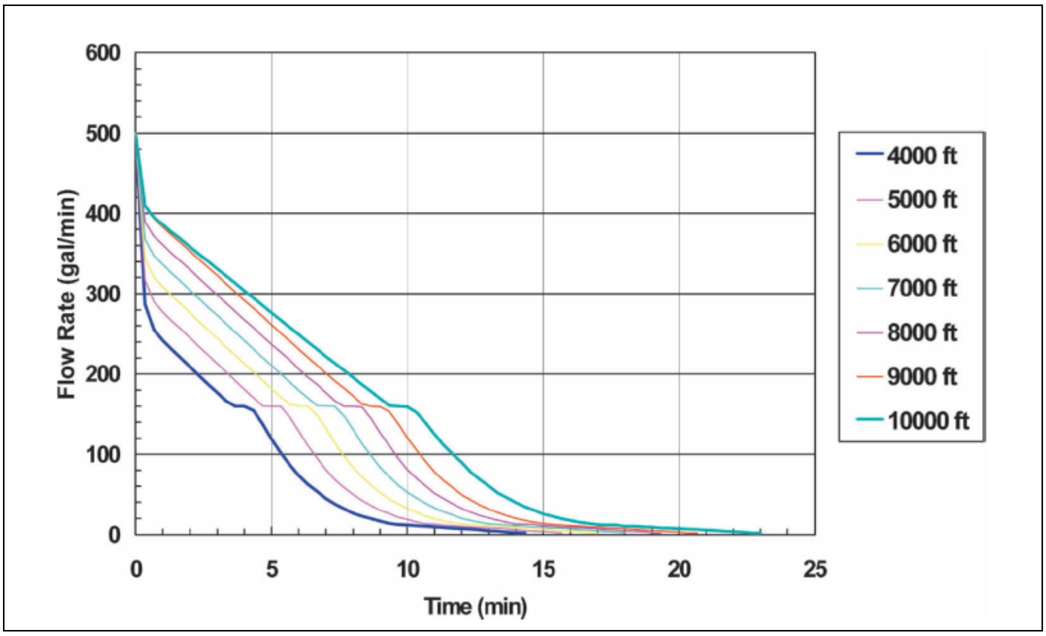

Figure 2.9: U-tube rate as a function of time for various water depths [16].

The Drill-String Valve (DSV) provides a solution to the u-tube effect. The DSV prevents the drillpipe from u-tubing into the well when circulation is stopped. With a DSV the drillpipe is full during connections and it makes most of the drilling process "look" very normal to the rig crews. Several versions of the DSV have been designed and built, but none are commercially available today [9]. Figure 2.10 shows the configuration of the DSV.

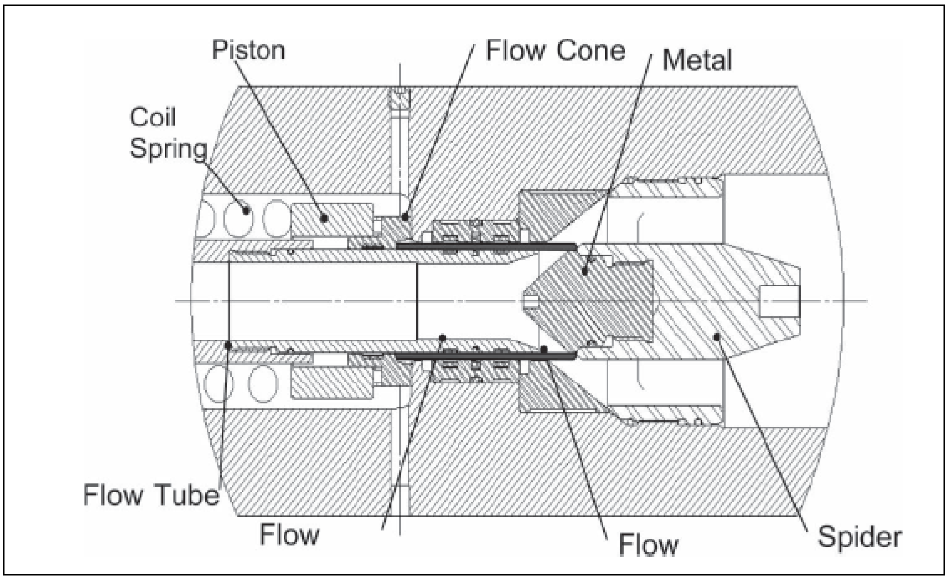

Figure 2.10: Drawing of the drillstring valve [17].

2.5.3 New Well Control Procedures

In order to use the DGD system new well control procedures are required. Those procedures are discussed in several DGD publications. DGD system differs from the conventional riser drilling, and therefore the well control procedures should be different.

In the paper of Schubert et al [1], the well control procedures needed for the SMD system were discussed in details. The new procedures were developed based on the dual gradient mud system, subsea pumps, RL, and operations with and without a specially designed drillstring valve (DSV) which is used to avoid the u-tube phenomenon. In addition the same study focused on the importance of developing the DSV due to its benefits in well control. A simulation study and a HAZOP (Hazard and Operability study) were performed to validate those new well control procedures. Prior to the test well, a training program was conducted for all personnel that were involved in the test [2]. Finally most of these well control procedures were tested on a test well.

Well control procedures should include all stages of drilling from the initial planning to completion and abandonment. The main target of well control is to avoid blowouts by: accurate predictions of formation pore pressure and fracture gradients, design and use of equipment (BOP, kick detection device, and casing), and proper kick detection and killing procedures [1].

2.5.4 Need for Topside/Rig Modifications

The majority of the offshore rigs were designed to be used in conventional drilling. Due to the differences between conventional drilling and DGD, modification must be done on rigs to accommodate this new system. These modifications can be very costly.

Examples of these modifications can be the ones described in the SPE paper of Schumacher et al [19]. Since SMD kill rates can be higher than conventional kill rates, the New Era's (the test drilling rig used by the SMD's JIP)gas buster was examined in detail. During the test well, the gas buster on the New Era will be required to accommodate only 100-150 gpm, although the SMD system allows for much higher kill rates. It is anticipated that gas busters used with the commercial SMD system will require modifications or redesign.

Another example of modifications can be the need of solids processing unit (SPU) in SMD operations [9]. The mudlift pump is not designed to handle solids bigger than 1½" x ½" x ½", in dimensions. The SPU is provided with cutters that shear anything larger than that. Solids smaller than the mentioned size will pass through the SPU without being affected.

2.5.5 Drilling Crew Familiarization with DGD

An important challenge of DGD is that drilling personnel need to be familiar with this method. People are required to change the way they work. Innovation of new technology needs trained people to succeed. Training is the tool that gives employees confidence to adapt to the technology. People confidence is a necessary factor in the overall technology success. The employees must be aware of the advantages and benefits of the new technology [9].

Chevron Oil Company was standing behind the deployment of the world’s first commercial DGD system [9]. Chevron has established the procedures needed to make its employees familiar with the SMD system. The procedures can be summarized in the following steps [9]:

- Getting employees to be engaged with DGD through being a part of the well planning team.
- Establishing good communications throughout the company by arranging series of “Lunch and Learn” sessions in 2009 to enable exchange of knowledge about DGD.
- Getting employees to be involved in the planning and operation, considering the needed changes in planning and operation of the DGD system.
- Arranging training courses that enable drilling team to deal with DGD. The training is generally divided along the following lines:

    1. Basic DGD Concepts
    2. Drilling Procedures
    3. Well Control Procedures
    4. Well Planning Procedures
    5. Maintenance Procedures for Specialized Equipment

3 Subsea Mudlift Drilling, SMD

3.1 SMD Overview

Figure 3.1 below shows the dual gradient system, known as the SMD system. The system is essentially a Subsea Mudlift System (SMS), due to its utilisations of Subsea Mudlift Pumps (SMP) to extract the mud return to the surface through an external conduit known as Return Line (RL). The RL is connecting the SMP outlet with the mud system on the surface, where the mud return is brought up for further processing. The marine riser is filled with seawater, while a heavy drilling fluid is filling the wellbore [20].

The SMD operation is outlined herein [20]:

1. Separation of the mud from the seawater: Drilling fluid contained in the wellbore is parted from the seawater contained in the main riser annulus through the utilisation of the Subsea Rotating Diverter (SRD); the diverter is able to withstand pressure difference approaching 34 bars.

2. Transferring of return mud and cuttings to the surface: This is done by the SMP through the RL. The SMP can usually deliver high flow rates, however along with mud there is usually debris, rock and stone cuttings. To maintain optimum flow rates, the ratio of the volumes delivered per hour of mud to cuttings should remain at 20:1 or lower.
3. The SMP design supports the optimum flow rate, defined as volume range: 2.4 – 408 m^3/h, maximum operation pressure at the inlet: 460 bars, and temperature range: 271 – 355 K. Moreover, the design enables 100% extraction of gas in the case of gas-kick.

4. Prevention of u-tube effect caused by the mud freefall from the drillstring into the well annulus: To prevent U-tubing, a Drill-String Valve (DSV) is installed at the BHA.

The u-tube effect occurs when the total friction loss in the drill-string and in the annulus is less than the hydrostatic pressure difference between the fluid levels of the drill-string and annulus. U-tube effect can mask kick incidents or make it difficult to detect kicks, and therefore it is important to be avoided by using the DSV [20].

General Fluid Control

The SMD system provides the driller with the benefit of adjusting the pressure at the surface pumps as per a conventional system. In addition the SMP would usually be run in automatic mode, i.e. it is run at a steady pre-determined inlet pressure. As the driller increases the speed of the mud pumps on the surface, subsequently the pressure at the inlet of the SMP will immediately rise, in response the speed of the SMP will automatically increase to lower the inlet pressure, hence stability [20].

On the other hand, a reduction of the speed on the surface pump, leads to a fall in the pressure at the inlet of the SMP, and as a result the speed of the SMP decreases in order to reach the specified stabilising pressure [20].

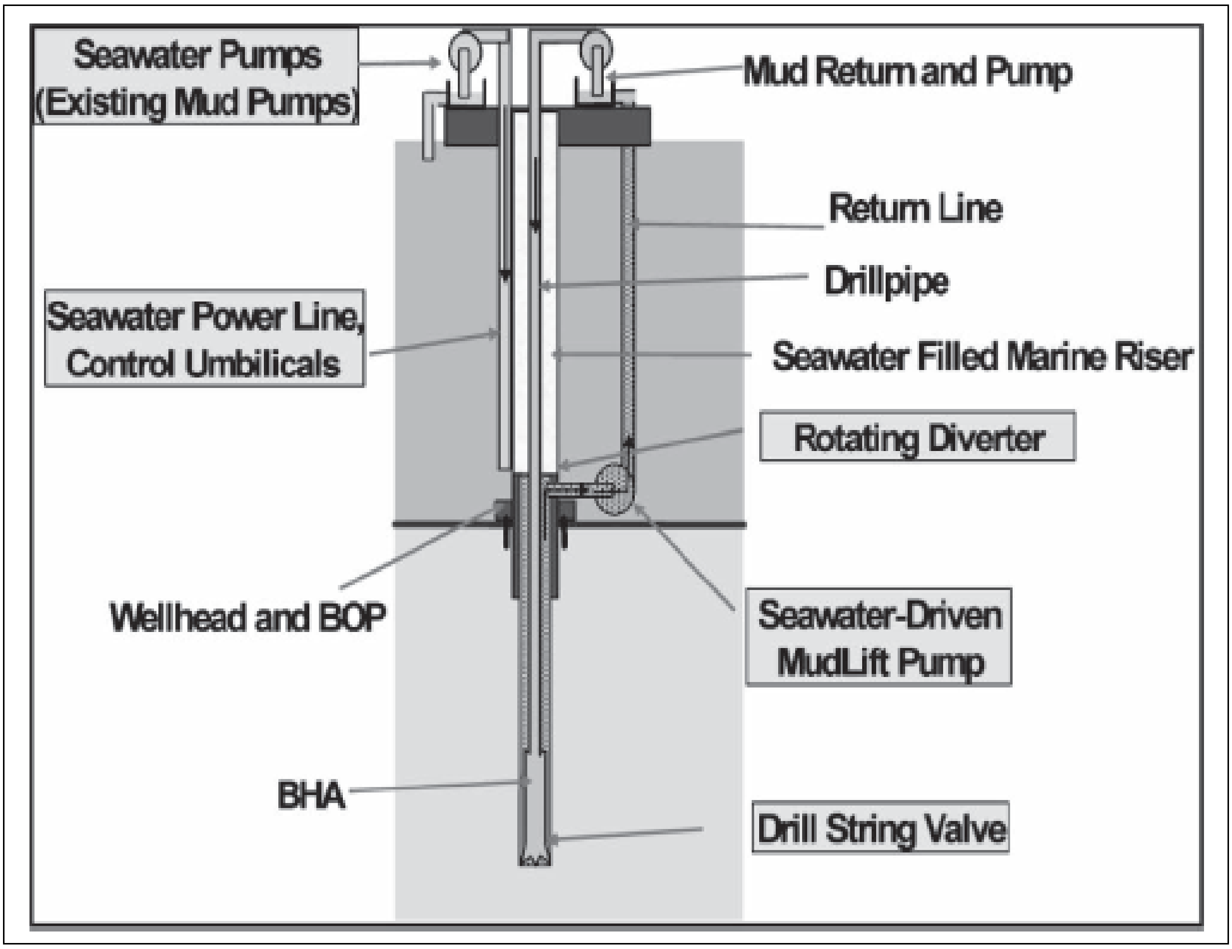

Figure 3.1: Subsea Mudlift Drilling- riser and equipment configuration [2].

3.2 SMD Equipments

In SMD operations many equipments for conventional drilling are used. However the SMD system has also unique equipments, which are listed below [9]:

Drill String Valve (DSV)

The DVS is used to avoid u-tubing of the drillpipe into the well when circulation is stopped. The DVS keeps the drillpipe full of drilling fluid during connections, and it makes most of the drilling process “look” very normal to the rig crews.

There are several configurations of DSV based on: drillpipe sizes, water deph and well depth. The DSV should be chosen to fit the conditions where it shall be used. Several DSVs have been designed, but they are still not commercially available. A huge effort is put to develop the DSV due to its importance in SMD operations.

Subsea Rotating Diverter (SRD)

The SRD is very similar to a common drilling rotating head (Figure 3.2), and it is the uppermost piece of equipment in the SMD system. It is usually located approximately 18 meters above the mud lift pump. The SRD’s function is to separate the seawater (or the fluid with density equal to that of seawater) in the riser from the heavy drilling fluid in the well. It ensures that gas doesn’t enter the riser and provides a slight pressure on the well.

The SRD sealing element with bearings and drillpipe seals is run on the drillstring and tripped to the surface during each drillpipe trip for maintenance. It can hold pressure from both below and from above.

Figure 3.2: Picture of the Subsea Rotating Diverter [9].

Solids Processing Unit (SPU)

The mudlift pump is not designed to handle solids bigger than 1½” x ½” x ½”, in dimensions. The SPU is provided with cutters that shear anything larger than that. Solids smaller than the mentioned size will pass through the SPU without being affected. After passing through the SPU, mud and cuttings are fed to the mudlift pump and pumped to the surface through a riser-mounted mud return line. The SPU riser joint is usually located about 9 meters above the mudlift pump and will also have a pressure rating equivalent to the riser. Several valves are available to control the flow into the mudlift pump.

MudLift Pump (MLP)

The MLP is the most important equipment in the SMD system (Figure 3.3). As originally decided in the SMD joint industry project, the MLP is a sixchamber (80-gallon) diaphragm pump powered by seawater pumped from the surface. It is a positive displacement type pump with independently controlled suction and discharge valves. Because each chamber can be operated independently, the MLP can operate as two triplex pumps, a quintaplex, a quadraplex, a triplex, a duplex or as a single chamber pump. This ability results in redundancy when the pump is operating at less than maximum capacity [9].

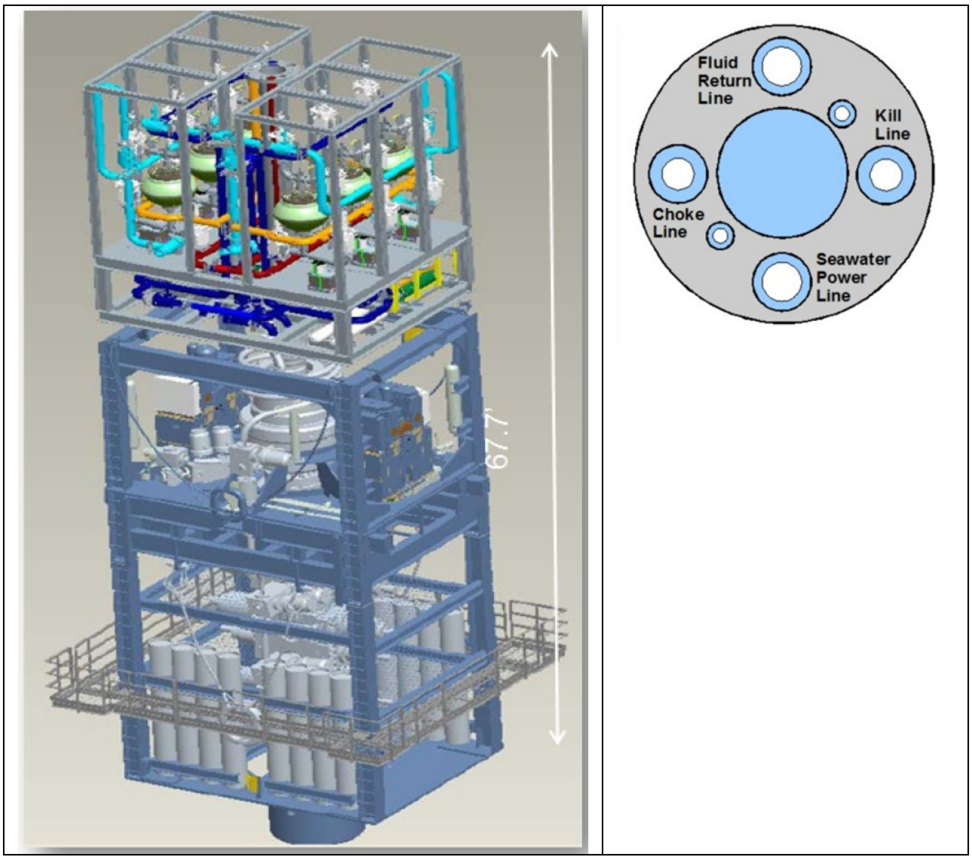

Figure 3.3: Drawing of the Subsea Mudlift Pump (left), and the associated lines that enter the pump [9].

Riser Dump Joint (RDJ)

During the numerous riser analyses performed, it became obvious that having the SRD in the riser would impact emergency riser disconnects. The SRD traps the fluid in the riser and does not allow for the free exchange of seawater in and out of the riser after an emergency disconnect as would happen with conventional systems. Trapping the fluid in the riser increases the loads on the riser during the rapid up and down movement of riser. During rough sea states, these loads might become too great for the riser system. Solving this problem required either a much stronger riser or a way of allowing the riser fluid/seawater to freely move in and out of the riser tube [9].

The solution was to install a modified riser dump joint in the bottom of the riser. This riser dump joint (RDJ) opens during an emergency disconnect and allows the free movement of fluids to reduce riser loading [9].

3.3 SMD Well Control

Fluid control during loss

If the bottomhole pressure exceeds the formation fracture pressure, the exposed formation will crack and the mud will leak into the formation causing loss circulation. This will lead to unexpected and unmanaged pressure drop at the inlet to the Subsea Mudlift Pump (SMP). The automatic response would be a consequential drop in the SMP rate. The driller will only observe trend changes at significant losses. The key signs to lookout for are [20]:

1. Pressure drop at the inlet to the SMP.

2. Reduced rate of SMP.

3. Pressure drop at the outlet from the SMP.

4. Surface pump pressure fall due to reduced friction losses in the annulus.

Kick Detection

Early kick detection is very essential for proper well control. Delay in kick detection can lead to serious blowout incidents. Drillers are usually provided by visual and audible alarms to detect kicks. The most common kick indicators are [1]:

- Drilling break.
- Flow increase.
- Pit gain.
- Decrease in circulating pressure and an increase in pump speed on the surface pumps.
- Well flows with the rig pumps off.
- Increase in rotary torque and drag.
- Increase in string weight.

These kick indicators are more noticeable when using SMD system than for conventional drilling. In SMD operations, pressure gauges with greater sensitivity are installed on the rig pumps. So an increase in flow, and decrease in circulating pressure will be easier to observe. When a kick occurs, the annular flow rate increases by an amount equal to the influx rate. This increase in annular flow is associated with an increase in the rate of the subsea mudlift pump, if the subsea mudlift pump is set in a constant inlet pressure mode. The use of very sensitive pressure gauges on the inlet and outlet of the subsea pumps along with accurate flow meters on the subsea pump outlet provides additional kick indicators [1].

When the rig pumps are set off, u-tubing of the mud from the drillstring can occur. This will lead to flow disruptions unless there is some means to prevent the u-tubing without applying additional hydrostatic pressure on the weaker shallow formations. The u-tube is challenging due to that it can mask/hide kick incidents. The drillstring valve (DSV) is usually used to prevent u-tube effect. The DSV is designed to have opening pressure greater than the difference in hydrostatic pressure of the mud in the drillstring and that of seawater at a depth equal to the water depth. With no u-tubing, the subsea pumps continue to operate (if the inlet pressure is set at seawater hydrostatic pressure) in a kick situation, analogous to the well flowing with the pumps off [1].

50 % of the kicks take place tripping the pipe in or out of the wellbore (mostly tripping out). Measuring the volume of mud required to fill the hole after removing a part of the drillstring (usually every five stands of drillpipe), gives usually the best and the earliest indication of a kick. If the volume to fill the well is less than the volume of steel removed, a kick may have occurred. If the DSV is not used, an accurate volume of mud required to replace the steel removed, can not be measured before the u-tubing of the drillstring has stopped [1].

Shut-in Procedures

When the kick is observed, the inflow of formation fluid should be stopped with time dependent procedures. This is very important to avoid formation fracturing and lost circulation, or the worse case, development of the kick into a blowout. This is usually done by shutting in the well with the BOP stack. The proper shut-in procedure is decided based on: the operation being performed at the time of the kick (drilling or tripping), equipment available, and other surrounding conditions. The heavy drilling fluid used in SMD operation does not allow immediate shut-in of the well without causing formation fracture unless the DSV is used to avoid u-tubing. If no DSV is installed, the mud in the drillstring should be allowed to u-tube into the annulus and up the return line before shutting in the well completely. During the u-tubing process, it is very difficult to prevent additional influx of formation fluid into the wellbore [1].

The influx is stopped and circulated from the wellbore without complete shut-in when employing the following procedures [1]:

1. Slow the subsea pumps to the pre-kick rate (maintain the rig pumps at constant drilling rate).
2. Allow the drillpipe pressure to stabilize, and record this pressure and the circulating rate.
3. Continue circulating at the drillpipe pressure and rate recorded in step 2 until kick fluids are circulated from the wellbore.
4. The constant drillpipe pressure is maintained by adjusting the subsea pump inlet pressure in a manner similar to adjusting the casing pressure with the adjustable choke on a conventional kill procedure.
5. After the kick fluids are circulated from the wellbore, a kill fluid of higher density is circulated around to increase the hydrostatic pressure imposed on the bottom hole.

The use of a DSV allows the well to be shut in immediately upon detection of the kick, and the well is killed in a manner more similar to conventional methods.

Calculation of kill weight mud (KWM)

Once the shut-in drillpipe pressure (SIDPP) is measured, the kill weight mud for conventional drilling can be calculated by using the following equation [1]:

$$KWM = \frac{SIDPP}{0.0981 * TVD} + OWM \tag{3.1}$$

This gives the KWM in specific gravity (sg), if the SIDPP is measured in bars, true vertical depth (TVD) in meters and the original weight mud (OWM) in sg.

For SMD all equivalent densities must be calculated with respect to the seafloor, not the rig floor. That means TVD minus water depth (WD). For DGD well control KWM is calculated by [1]:

$$KWM = \frac{SIDPP}{0.0981 * (TVD - WD)} + OWM \tag{3.2}$$

Driller's Method

The Driller's Method is a method that employs constant bottomhole pressure circulation to circulate kicks from the wellbore. When using this method, two complete circulations are needed to kill a well. Once a kick is detected, the well is shut in long enough to measure stabilized SIDPP, shut-in casing pressure (SICP), and pit gain, then the kick fluids are circulated from the wellbore with original weight mud, maintaining the pump rate at a predetermined kill rate. The circulating drillpipe pressure is maintained at Initial Circulating Pressure (ICP) while the formation fluids are being circulated from the wellbore, after which the well is again shut in. Mud in the surface pits is weighted up to KWM, and circulated around the wellbore at kill rate following the Drillpipe Pressure Decline Schedule (DPDS). Once kill mud reaches the bit, final circulating pressure is maintained until the well is filled with KWM [1].

To avoid additional unnoticed influx during u-tubing in SMD operations, a modified Driller's method has been developed. This is described in details in "Shut-in Procedures" section. The procedure to be followed here is for the case with no DSV, the well will then not be closed immediately. One of the surface mud pits is weighted up to KWM, while circulating the kick fluids from the wellbore. Once the formation fluids are circulated from the wellbore, rig pump suction is switched to the pit containing KWM and the OWM is circulated from the wellbore following the drillpipe pressure decline schedule [1].

By using the DSV, the well can be shut in immediately upon kick detection, and no modifications are needed for the Driller's method, except for determination of the DPDS. The DPDS is identical to conventional riser drilling when no DSV is used in SMD operations, assuming circulating rate is greater than free fall rate. If the DSV is installed in the drillpipe the DPDS should be modified.

The DSV is designed so that its opening pressure can be set to be greater than the difference between the hydrostatic pressure of the mud in the drillpipe and the seawater hydrostatic pressure at the mudline plus an additional margin to allow for increasing the mud weight. Every time the kick kirculating pressure is measured the DSV opening pressure should be measured. When a DSV is installed, no modification is needed for the ICP. However the Final Circulating Pressure (FCP) should be modified considering the change in DSV opening pressure due to the heavier kill mud. The FCP is then to be obtained from [1]:

$$FCP = (\Delta P_{dp\_bit} - AFP) \times \frac{KWM}{OWM} - DSV_{set} + AFP \tag{3.3}$$

Where:
ΔP_{dp_bit} = Frictional pressure in the drillstring plus the bit pressure drop.
AFP = Annular frictional pressure
DSV_{set} = The difference in hydrostatic pressure between the KWM and seawater at the mudline

An alternative to monitoring the circulating drillpipe pressure during the entire kill is available, and is as follows [1]:

1. Circulate kick fluids from the well, maintaining ICP on the drillpipe pressure.
2. Shut-in the well, record subsea pump inlet pressure and weight up mud system to KWM.
3. On the second circulation maintain subsea pump inlet pressure at the value recorded in Step 2 while circulating KWM to bit. It is essential that all the gas has been removed from the annulus for this pressure to be valid.
4. Once KWM reaches the bit, record the circulating drillpipe pressure, and maintain this constant drillpipe pressure and rate until KWM is circulated back to the surface.

Wait & Weight Method

In Wait and Weight method, one circulation is theoretically used to kill the well. The stabilized SIDPP, SICP, and Pit gain are recorded, once the kick is detected and the well is shut in. SIDPP is used to calculate KWM, and the mud in the surface pits is weighted up to kill weight. The well remains shut in during the weight up process. As soon as KWM is mixed, circulation of the well follows the pressure decline schedule. After KWM reaches the bit, final circulating pressure is maintained until the entire wellbore is filled with KWM. This procedure is followed, almost without change for DGD with a DSV, except for the difference in construction of the pressure decline schedule discussed above. The Wait and Weight method is not preferred if no DSV is used, due to the u-tubing problem, and the lack of a readable drillpipe pressure while re-filling the drillstring when circulation is re-started [1].

Volumetric Method

The volumetric method is usually used in case of gas kick in closed well where circulation is not possible for one reason or another. This can be due to power failure, plugged drillstring, or the pipe is out of the hole. With the volumetric method, the gas bubble is allowed to expand while migration upwards to prevent building up of surface pressure with gas migration. To achieve that the shut-in pressures are allowed to rise to a predetermined level, which is chosen to not exceed the level of formation fracture. Then bleeding a small amount of mud from the annulus in stages, this will result in decreasing the gas bubble pressure as well as the surface pressure and the gas bubble is allowed to expand. The mud should be bled in small amounts on a time to avoid additional gas influx. The proper way of preventing a new kick is by monitoring the SIDPP (if possible), and maintaining the SIDPP slightly greater than the original recorded on initial shut-in [1].

If the SIDPP cannot be monitored, a casing pressure schedule is constructed which allows for the correct expansion of the gas as it migrates up the wellbore. In SMD operation the same procedure and pressure schedule for conventional riser drilling are followed. The only difference is that the mudlift pump inlet pressure is used instead of the SICP, and the subsea pumps automatically bleed the correct volume of mud from the wellbore [1].

4 Low Riser Return System, LRRS

4.1 LRRS Overview

Figure 4.1 below depicts the LRRS, which is categorised as a Subsea Mudlift System (SMS) since it utilises a sub-sea pump to transport the mud return back to the surface through an external pipe (usually called the Return Line (RL)), which connects the outlet device jointed with the marine drilling riser with the mud system on the surface. The system utilizes a centrifugal subsea pump with maximum rate of around (240 m^3/hour). The gas contained in the drilling fluid reduces the pump capacity of the subsea pump; therefore the gas fraction should be as low as possible [20].

The marine drilling riser is partly filled with drilling fluid, and the rest of the riser is filled with gas at approximately atmospheric pressure. There is no sealing element between the mud and the gas in the marine riser. A wiper element is located below the rotary Kelly bushing to avoid gas leakage from the wellbore, other than through the vent line from the diverter. The LRRS allows gas to pass through the marine riser [20].

The LRRS is utilized by a booster pump on the surface in addition to the main mud pumps, used to fill the riser annulus when needed. This pump is often called fill pump, and it is designed to deliver a maximum rate of about (240 m^3/hour). When the mud level in the marine riser is located below the sea level, a heavier than conventional mud is used. This makes it challenging to circulate mud through the choke line due to the possibility of formation fracturing. To avoid this issue a bypass (BP) line is used to circulate mud from below the BOP and into the marine riser. An adjustable subsea choke (SSC) is used to control the back pressure. The SSC has the same function as the conventional adjustable surface choke valve [20].

The LRRS is invented by Ocean Riser Systems [18]. The company has designed two versions of the system, LRRS Light and LRRS Heavy [10]:

3. LRRS Light is used for ECD compensation and improved kick loss detection. It uses conventional well control procedures, and requires minimal incremental rig integration.

4. LRRS Heavy, on the other hand, uses a heavier than conventional mud, which would in most cases fracture the formation if the mud level were to be brought to surface. This system is dependent on the LRRS well control procedures [14], including a subsea drilling choke with some additional equipment and implementation of appropriate well control training.

LRRS Improves Cementing

In reservoirs with small margin between pore/fracture gradients margin, it is challenging to achieve a good cement job. With conventional drilling, this will usually be solved by lowering the cement density, which leads to poor cement jobs and all the problems related to that (e.g. poor zonal isolation). By using the LRRS it is possible improve cementing by compensating for density and ECD effects [10].

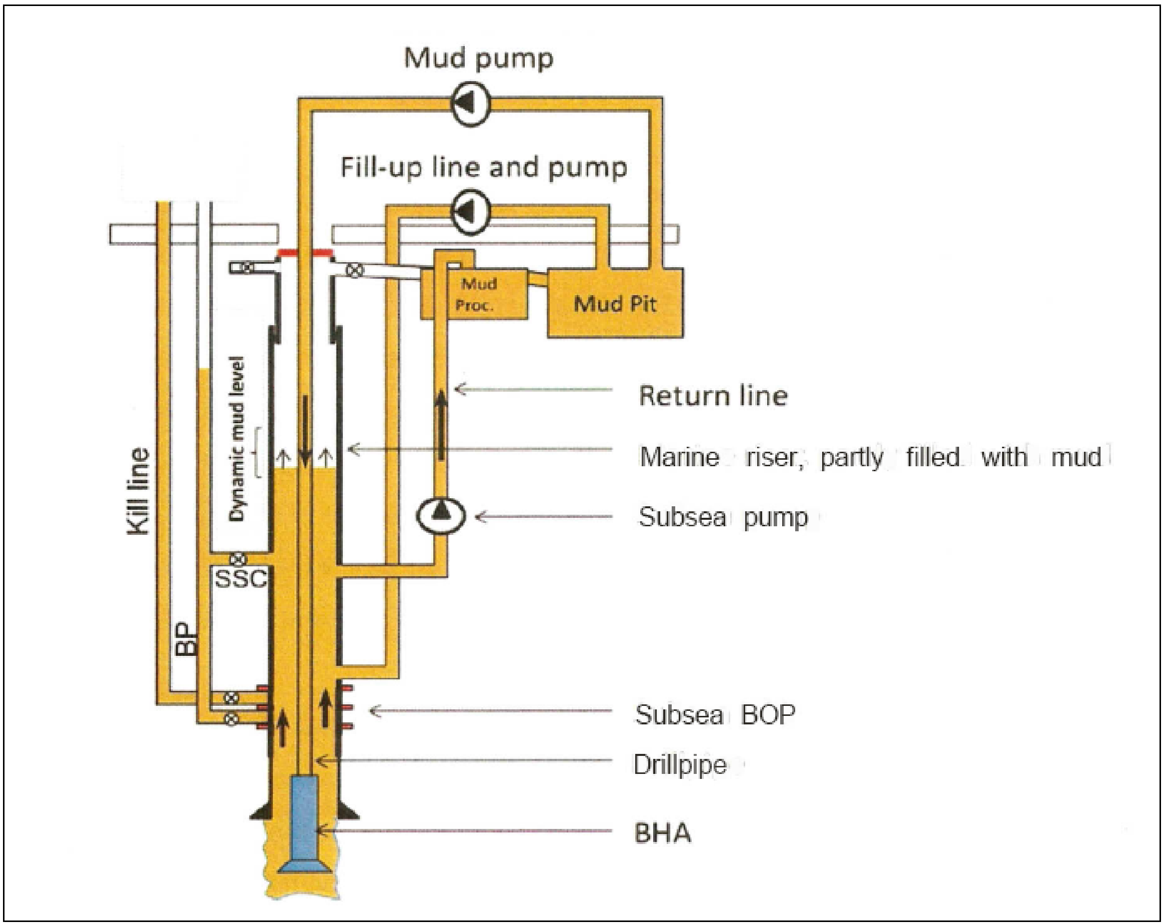

Figure 4.1: The Configuration of the Low Riser Return System (LRRS) [20].

4.2 LRRS Well Control

Influx and Loss Detection

It is easier to detect formation fluid influx and losses by using the LRRS than with conventional drilling. The most important kick indicator during steady state operations is that more volume needs to be pumped out of the hole than what goes in. Sequentially the pump speed and power will increase. This would be detected by the control system linked to the level in the riser. It is important to note that the mud level in the riser is not affected by rig movement like the conventional mud line on a floater [10].

With the LRRS an accurate flow measurement can be sufficient to detect kicks and there will be no need for intensive flow checks or to wait for a large pit gain. Accurate flow measurement will assist in initiating well control procedures earlier, and hence prevent serious blowouts. When a potential influx is detected the procedures is to immediately turn down or stop the LRRS return pump. This will increase the riser level and hence bottomhole pressure [10].

Procedures for Circulating Out an Influx with LRRS Heavy

With LRRS Light the influx can be safely circulated out using conventional well control procedures, while LRRS Heavy requires special LRRS well control procedures. The LRRS well control procedures are based on Drillers Method circulating out with constant drill pipe pressure adjusting a subsea choke. The principle differences between conventional circulation procedures and the LRRS Heavy procedures are explained as follows [10]:

1. Drilling with a LRRS Heavy means that the mud weight is higher than maximum achievable kill mud weight conventionally.
2. The well may not be shut in with the drill pipe full of drilling fluid as conventional. Either of the two alternatives below would prevent the formation from “seeing” the hydrostatic pressure of the drilling fluid from surface:
    a) Install a drillpipe differential pressure valve.
    b) Initialize the LRRS circulation procedures and U-tube the drill string prior to closing the well.
3. The choke line incorporates a subsea choke valve and a low-pressure bypass from the choke line into the main bore of the riser a distance above the outlet to the LRRS pump.
4. The well can be brought to overbalance dynamically by increasing the mud level in the riser, hence normally there is no need to weigh up the mud.
5. The BOP is normally closed during a kick circulation but there may not be a hurry to shut in well by closing a BOP element.
6. The kick is circulated out of the well using the Constant Drill Pipe Pressure (CDPP) principle where CDPP is kept constant by regulating the pressure on the subsea choke valve. Alternatively, a minor influx can also be circulated out without shutting in the well (closing a BOP element) and regulating the liquid height. However, this is not the primary method.

5 Drift Flux Model

5.1 Conservation Equations

The Drift Flux model is based on conservation laws for two phase flow, and it aims to describe the characteristics of the flow in pipes or wells (primarily one dimensional modelling). Due to the complications associated with the two phase conservation laws, a third momentum conservation equation is added for the mixture flow (liquid and gas). Furthermore the energy component is eliminated based on the assumption of no significant temperature changes occur within the system (isothermal flow). The drift flux model for two phase flow in isothermal conditions, and where the flow area is constant, can be presented as follows [21]:

$$\begin{aligned}
&\partial t\,(\alpha_g \rho_g) + \partial x\,(\alpha_g \rho_g v_g) = \Gamma_g \\
&\partial t\,(\alpha_l \rho_l) + \partial x\,(\alpha_l \rho_l v_l) = \Gamma_l \\
&\partial t\,(\alpha_g \rho_g v_g + \alpha_l \rho_l v_l) + \partial x\,(\alpha_g \rho_g v_g^2 + \alpha_l \rho_l v_l^2 + p) = -q
\end{aligned} \tag{5.1}$$

Where:

α_g, α_l are volume fractions of gas and liquid.

ρ_l, ρ_g are densities of liquid and gas.

v_l, v_g are velocities of liquid and gas.

Γ_l, Γ_g are mass exchange between the two phases, liquid and gas.

p is the pressure.

$(q = F_w + F_g)$ is the external forces acting on the fluids, where F_w is the frictional forces between the fluid and the wall, and $(F_g = g\,(\rho_l \alpha_l + \rho_g \alpha_g)\cos\theta)$ is the gravitational forces (g is the gravity and θ is the inclination).

Under the assumption of no mass exchange between the two phases $(\Gamma_l = \Gamma_g = 0)$, the equation system (5.1) can be written in the following conservative vector form:

$$\partial t\, w + \partial x\, F(w) = G(w) \tag{5.2}$$

Where:

$$w = \begin{pmatrix} \alpha_l \rho_l \\ \alpha_g \rho_g \\ \alpha_l \rho_l v_l + \alpha_g \rho_g v_g \end{pmatrix},\ F(w) = \begin{pmatrix} \alpha_l \rho_l v_l \\ \alpha_g \rho_g v_g \\ \alpha_l \rho_l v_l^2 + \alpha_g \rho_g v_g^2 + p \end{pmatrix}\ \text{and}\ G(w) = \begin{pmatrix} 0 \\ 0 \\ -q \end{pmatrix} \tag{5.3}$$

The equation above can be written in the following way as well:

$$\partial t \begin{pmatrix} w_1 \\ w_2 \\ w_3 \end{pmatrix} + \partial x \begin{pmatrix} v_l w_1 \\ v_g w_2 \\ v_l^2\, w_1 + v_g^2\, w_2 + p\,(w_1, w_2) \end{pmatrix} = \begin{pmatrix} 0 \\ 0 \\ -q \end{pmatrix} \tag{5.4}$$

Where: $w_1 = \alpha_l \rho_l$, $w_2 = \alpha_g \rho_g$ *and* $w_3 = \alpha_l \rho_l v_l + \alpha_g \rho_g v_g$, Pressure and volume fractions are physical variables that depend on the conservative variables w_1 and w_2 [21].

5.2 Closure Laws

The closure laws assist the drift flux model to deliver better approximation of the real flow conditions. In addition the closure laws are needed to close the system as the number of equations should be equal to the number of unknowns. Therefore it is important to ensure that the closure laws used in the model are valid for that specific situation. The closure laws can be determined experimentally or by using theoretical equations.

In the paper of Evje and Fjelde [21], simple closure models for the drift flux model were presented. These closure models includes: slip, density and friction of both phases.

1) **Slip law:**

An analytical slip law was assumed, and takes the following form:

$$v_g = K v_{mix} + S \qquad \textbf{(5.5)}$$

Where: $v_{mix} = \alpha_l v_l + \alpha_g v_g$ is the mixture average velocity and K,S are flow dependent parameters. This expresses that gas migrates faster upwards than liquid in a well.

2) **Liquid and gas densities:**

Liquid density is assumed to be:

$$\rho_l = \rho_{l,0} + \frac{p - p_{l,0}}{a_l^2} \qquad \textbf{(5.6)}$$

Where: a_l = 1000 m/s is the velocity of sound in the liquid phase and $\rho_{l,0} = 1000\ kg/m^3\ and\ p_{l,0} = 1\ bar$ are reference values for density and pressure at atmospheric conditions respectively.

The gas density is assumed to be:

$$\rho_g = \frac{p}{a_g^2} \qquad \textbf{(5.7)}$$

Where: $a_g = 316\ m/s$ is the velocity of sound in gas phase and p is the pressure in Pascal.

3) **Volume fractions:**

The following relation applies to the volume fractions $\alpha_l\ and\ \alpha_g$:

$$\alpha_l + \alpha_g = 1 \qquad \textbf{(5.8)}$$

4) The source term q:

The source term q represents the external forces acting on the fluids, and it is the sum of gravitational force (F_g) and the frictional pressure loss (F_w). A slightly more complex frictional pressure loss model has been used in the AUSMV scheme. This frictional model is considered for the cases where annular flow geometry has been assumed. The frictional pressure loss term is then given by [26]:

$$F_w = \frac{2\, f\, \rho_{mix} v_{mix}\, abs(v_{mix})}{(d_{out} - d_{in})} \qquad \textbf{(5.9)}$$

Where: d_{in} and d_{out} are the inner and outer diameter of the annular flow area and f is the friction factor. The friction factor is to be obtained by using different models based on the type of flow regime (laminar or turbulent flow). The transition between the two flow regimes is determined from the Reynolds number obtained by:

$$\mathrm{Re} = \rho_{mix}\, abs(v_{mix})(d_{out} - d_{in}) \,/\, \mu_{mix} \qquad \textbf{(5.10)}$$

The flow is considered laminar when Reynolds number is less than 2000, and the friction factor is given by: $f = 24/\mathrm{Re}$. If the Reynolds number is larger than 3000, the flow is considered turbulent and the friction factor is to be obtained by: $f = 0.052\,\mathrm{Re}^{-0.19}$. A smooth transition between the two flow regimes should be ensured.

5.3 Type of Mathematical System & Eigenvalues

The drift flux model is based on the conservation equations, which are a set of nonlinear partial differential equations. Such systems are usually classified as hyperbolic, parabolic or elliptic. The drift flux model is hyperbolic type, which means that the system generates shock waves. Shock waves are difficult to handle numerically [22].

Eigenvalues and eigenvectors assist on defining the right conditions at the flow boundaries [22]. Under the condition of incompressible liquid flow, and when [21]:

$$\alpha_g \rho_g << \alpha_l \rho_l \qquad \textbf{(5.11)}$$

for two phase flow and where $\alpha_g \in (0,1)$ the following approximation applies to sound velocity:

$$\omega^2 = \frac{p}{\alpha_g \rho_l (1 - K\alpha_g)} \qquad \textbf{(5.12)}$$

The eigenvalues are then given by:

$$\lambda_1 = v_l - \omega, \quad \lambda_2 = v_g, \quad \lambda_3 = v_l + \omega \qquad \textbf{(5.13)}$$

The first and the third eigenvalues refer to the pressure pulses propagating downstream and upstream. The second eigenvalue refers to the wave speed of the gas volume wave travelling downstream. For pure liquid flow ($\alpha_g = 0$), the following eigenvalues are obtained:

$$\lambda_1 = v_l - a_l, \quad \lambda_3 = v_l + a_l \qquad \textbf{(5.14)}$$

Where a_l is the sound velocity in the liquid phase. These two eigenvalues refer to the pressure pulses travelling downstream and upstream. Furthermore for pure gas flow ($\alpha_g = 1$), the following eigenvalues are obtained:

$$\lambda_1 = v_g - a_g, \quad \lambda_3 = v_g + a_g \qquad \textbf{(5.15)}$$

Where a_g is the sound velocity in the gas phase.

5.4 Discretization

Discretization is widely used in computing context, where parameters change their values both in time and space. Generally discretization is the act of dividing the study area (e.g. a well) in finite number of units, usually with equal dimensions [25].

In order to solve the drift flux model, a discretization is needed. The well is then divided into N number of boxes (1, …, i -1, i, i +1, …, N) with equal length, Δx and time step, Δt (Figure 5.1). Each box has its corresponding conservative and physical variables.

The numerical approach of the conservation equations can be obtained by implicit or explicit approach. By using implicit technique, one obtains faster results but the technique is more complicated, and values of the variables are calculated based on the "new" values. In the implicit approach time steps can be larger, and depends only on the box length (Δx) and the maximum velocity of the fluid (v_{max}) [24]:

$$\Delta t = \frac{\Delta x}{v_{\max}} \tag{5.16}$$

For the explicit approach the values of the variables are calculated based on the "old" values. The time step depends on: the box length (Δx), the velocity of the fluid (v) and the speed of sound (c), and it is limited by the following criterion:

$$\Delta t < \frac{\Delta x}{v + c} \tag{5.17}$$

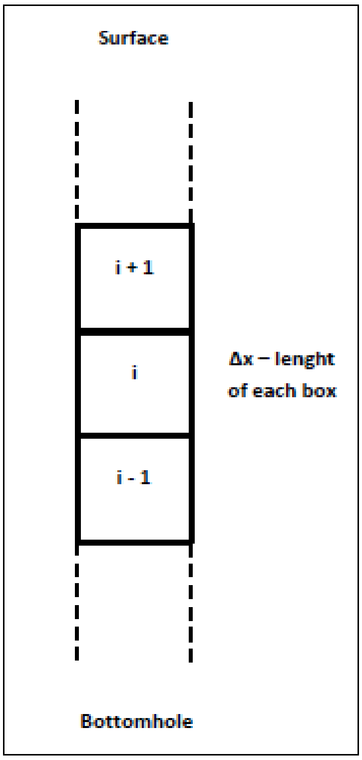

Figure 5.1: Discretization of a vertical well [23].

6 AUSMV Scheme

6.1 AUSMV Scheme Overview

The AUSMV scheme is an alternative numerical solution technique for the drift flux model, which is used to analyse the flow of liquid and gas in a well or a pipeline. The AUSMV is the abbreviation for (Advection Upstream Splitting Method), the V at the end refer to the velocity splitting functions, $\tilde{V}^{\pm}$ used in this scheme, which differs from the velocity splitting functions ($V^{\pm}$) used in the other numerical schemes. The velocity splitting function $\tilde{V}^{\pm}$ is defined as follows [21]:

$$\tilde{V}^{\pm}(v,c,\chi) = \begin{cases} \chi V^{\pm}(v,c) + (1-\chi)\frac{v \pm |v|}{2} & |v| \le c \\ \frac{1}{2}(v \pm |v|) & \textit{otherwise} \end{cases} \tag{6.1}$$

Where: v is the fluid velocity, c is the sound velocity and χ is a constant parameter that can be chosen in a specific way to avoid numerical dissipation in the results.

The AUSMV scheme is based on the hybrid Flux-Vector Splitting (FVS) scheme, and it provides an explicit solution to the conservation equations. This means that by using this scheme the values of the variables, will be calculated using the “old” values. By using the AUSMV together with discretization, the values in a further new time step level (n+1) can be found by [21]:

$$w_{i,j}^{n+1} = w_{i.j}^{n} - \frac{\Delta t}{\Delta x}\left(F_{j+\frac{1}{2}}^{AUSMV} - F_{j-\frac{1}{2}}^{AUSMV}\right) - \Delta t\, q_i^n \tag{6.2}$$

Where: $w_{i,j}$ are the mass conservative variable and momentum conservative variable for i = 1, 2 and 3, q_i is the external forces acting on the fluid (see chapter 5.1), and F^{AUSMV} is the mass flux obtained by the following equation [21]:

$$F_{j+\frac{1}{2}}^{AUSMV} = v\rho(p)\frac{\alpha_L + \alpha_R}{2} - \frac{1}{2}|v|\rho(p)\left[\alpha_R - \alpha_L\right] \tag{6.3}$$

Where the denotation: R and L refer to the right and the left boundary of the box. Since the AUSMV is an explicit solution scheme, the time steps must be determine based on the CFL (Courant-Friedrichs-Lewy) criterion [21].

$$\Delta t = CFL\frac{\Delta x}{\max(|\lambda_1|,|\lambda_2|,|\lambda_3|)} \tag{6.4}$$

Where λ_i represents the eigenvalues of conservation equations (chapter 5.3). For more details about the AUSMV scheme refer to references number [21] and [26].

It is obvious that wells and pipelines usually don't have a constant flow area, and therefore equation (6.2) should be modified to handle such situations. The modified equation is as follows [26]:

$$w_{i,j}^{n+1} = w_{i.j}^{n} - \frac{\Delta t}{\Delta x}(A_R\, F_{m,\, j+\frac{1}{2}} - A_L\, F_{m,\, j-\frac{1}{2}} + A_{avg}\,(F_{p,\, j+\frac{1}{2}} - F_{p,\, j-\frac{1}{2}})) - \Delta t\, q_i^n \qquad \textbf{(6.5)}$$

Where: F_m represents the convective fluxes and F_p represents the pressure fluxes. A_L and A_R are the flow area at the left and the right side of the numerical box, and ($A_{avg} = 0.5\ (A_L + A_R)$) is the average flow area (Figure 6.1).

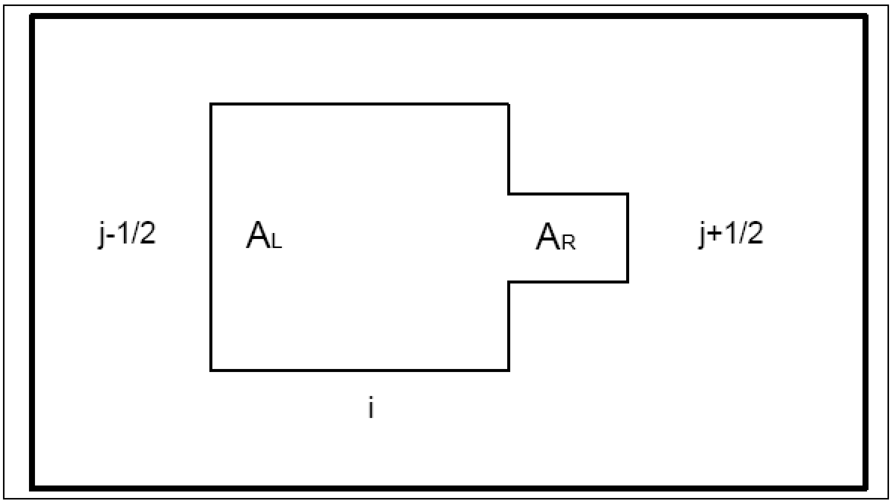

Figure 6.1: Flow Area Change [23].

After finding the conservative variables: w_1, w_2 *and* w_3 from equations (6.2) or (6.5), the physical variables (pressure, liquid and gas densities, volume fractions and phase velocities) can be calculated using the relations described in the chapter describing the closure laws.

The AUSMV scheme has been used in the simulation of the SMD system described in chapter (7). The scheme is programmed using the Matlab software to ease the calculations, the Matlab code was then extended to simulate the SMD conditions.

6.2 Treatment of Boundary Conditions

The AUSMV scheme takes care of all variables connected to the numerical boxes inside the flow area. The values at the flow boundaries should be fed to the scheme in order to do the rest of calculations. The boundary conditions specify the type of the system that will be analysed.

The boundary conditions are directly dependent on the eigenvalues. The eigenvalues determine how many of the input values must be specified (physical boundary condition), and how many can be extrapolated (numerical boundary condition). If one-phase flow is considered, two eigenvalues are obtained (see chapter 5.3), which means that only one boundary condition variable can have a fixed value, while the second one should be extrapolated. In other words, one fixed and one extrapolated variable at the inlet of the system and one fixed and one extrapolated variable at the outlet.

In the first set of SMD simulation (one-phase flow), the inlet/outlet liquid massrates had been specified, while the inlet/outlet pressures were extrapolated. The inlet pressure was then extrapolated by using the following equation:

$$p_{inlet} = p(1) + 0.5(p(1) - p(2)) \tag{6.6}$$

Where: the indexes 1 and 2 refer to the first and the second numerical boxes. The outlet pressure was extrapolated by using the same method.

In the second set of SMD simulation (two-phase flow (kick situation)), the system has three eigenvalues. Therefore two boundary condition variables could be specified, while the third one must be extrapolated at the inlet of the system. More precisely in this simulation, the inlet liquid and gas massrates were specified and the inlet pressure was extrapolated. At the outlet only one variable can be specified, while two variables must be extrapolated. In this case one should choose on of the following alternatives:

1. Alternative 1: Specify the outlet pressure and extrapolate the outlet gas and liquid fluxes.
2. Alternative 2: Specify outlet liquid massrate and extrapolate the outlet pressure and the outlet gas fluxes.

Alternative 2 was implemented in the simulations presented in chapter 7.2.

7 Simulations & Results

In this chapter, two set of simulations will be presented. The AUSMV scheme with its corresponding Matlab code has been used to simulate the dynamics of the SMD system. The first test is a boundary condition test, and the second one is a simulation of an SMD kick situation. More details about the two set of simulations will be presented below.

7.1 Case 1: SMD Boundary Conditions Test

7.1.1 Test Background

The purpose of this test was to investigate the ability of the AUSMV scheme to handle the SMD system. A simple one-phase flow was considered in this test, which means normal drilling operation with the drilling fluid as the only fluid flowing in and out of the system. The test was designed to force the inlet liquid massrate to be slightly larger than the specified outlet liquid rate, and observe the development of the pressures in the wellbore, both bottomhole pressure and the pressure at the inlet of the Subsea Mudlift Pump (SMP).

7.1.2 Extensions of the AUSMV Code

No serious extensions to the AUSMV code were done in this test rather than defining the boundary conditions. The purpose was to investigate the ability of the scheme to handle the SMD system, therefore all procedures were kept as simple as possible.

1) Well Geometry

The well geometry used in this test was as follows:

- Well depth = 2000 m.
- Water depth was excluded from the calculations for simplicity. This is not very realistic since the SMD system is initially designed to be used in ultra deep water drilling, but for simplicity the well was designed to be onshore well (water depth = 0 m).
- Well inclination = 0˚(Vertical well), A smart trick was used in the AUSMV code, the well was initially defined as a horizontal well with 90˚inclination and then it has been lifted up gradually during the first 100 seconds of simulation to get the initial conditions in the well prior to starting the injection of fluids at the bottom. Therefore any thing happened before the first 100 seconds will not be considered in the simulation results discussed below.
- Wellbore diameter = 0.2159 m, typical 8 1/2" section well, and the wellbore diameter was assumed to be constant throughout the whole 2000 m depth.
- Drillpipe diameter = 0.127 m, (or 5" drillpipe), this was again assumed to be constant for the whole well depth. This is again not realistic due to that BHA, drilling bit and connections have larger diameter than the rest of the drillpipe. This

was assumed to make the simulation simpler. However the AUSMV scheme is designed to handle such flow area changes.

- The flow area was defined to be the annulus between the drillpipe and the wellbore: $Flow\ area = \frac{\pi}{4}(0.2159^2 - 0.127^2) = 0.0239\ m^2$
- Well opening was initially set to be 100 % (= 1), this has been changed to 0 % (= 0) due to that the SMD system is a closed system where the Subsea Rotating Diverter seals the mud inside the wellbore from contact with sea water contained in the marine riser. The flow rate at the inlet of the subsea pump was specified as the physical outlet boundary condition, while the pressure was found by extrapolation.

2) Fluid properties

Initial fluid properties were as presented in the following table:

Fluid Property	Liquid (Drilling Fluid)	Gas (Reservoir Fluid)
Density [kg/m]	1000	1.0
Viscosity [Pa s]	5×10^{-2}	5×10^{-6}
Sound Velocity in the Fluid [m/s]	1000	316

Table 7.1: Fluid properties used in the simulation of Case 1.

Fluid properties during the simulations were taken care of by the closure laws provided with the given AUSMV code. See chapter (5.2) for more details about closure laws.

3) Boundary conditions treatment

The most important part of the simulation was to define the boundary conditions in order to simulate the SMD system. Four important variables were the key variables that have been modified to simulate the SMD system: inlet/outlet liquid massrates, bottomhole pressure (inlet pressure) and pressure at the inlet of the Subsea Mudlift Pump (SMP) (outlet pressure). The outlet liquid massrate was specified to be the liquid massrate at the inlet of the SMP. All fluid flow took place after 150 seconds from the simulation start, and no fluid flow was initiated before that. The total simulation time was 250 seconds. Table 7.2 presents the specified boundary conditions during the test. The rest of the boundary conditions were extrapolated. More precisely the fluid massrates were specified while the inlet and the outlet pressures were extrapolated.

Time [Seconds]	Inlet Liquid Massrate (Mud) [kg/s]	Inlet Gas Massrate (Reservoir Fluid) [kg/s]	Outlet Liquid Massrate (Mud) [kg/s]
150 to 160	22*(time-150)/10	0	21*(time-150)/10
160 to 250	22	0	21

Table 7.2: Fluid massrates used in the simulation of Case 1.

7.1.3 Simulation Results for Case 1

The following results have been obtained from the simulation of Case 1. Figure 7.1 shows the inlet and the outlet massrates used in the simulation of Case 1. It is noticeable that the inlet liquid massrate is slightly larger than the outlet liquid massrate, and both increased gradually during the first 10 seconds of the simulation depending on the time as mentioned in Table 7.2.

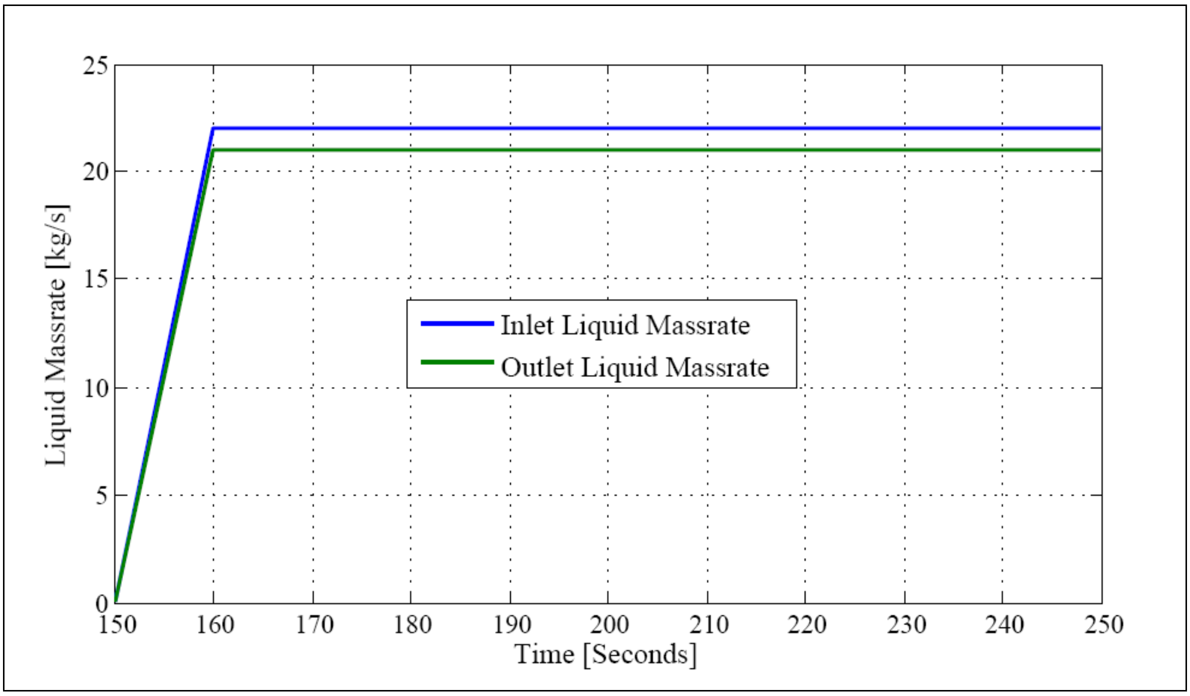

Figure 7.1: Inlet/outlet liquid massrates used in the simulation of Case 1.

Figure 7.2 shows the development of the bottomhole pressure during the simulation of Case 1. The bottomhole pressure increased rapidly in the beginning and then it was nearly constant during the time period 160 sec to 165 sec, then the pressure continued to increase with a constant rate slightly less than the one in the beginning. This rapid pressure increase in the beginning can be due to the frictional loss at the bottom of the well.

Figure 7.3 shows the pressure development at the inlet of the Subsea Mudlift Pump (SMP). The SMP pressure was constant (approx. 7 bars) during the first 10 seconds. This is higher than the surface pressure due to that the inlet of the SMP is placed below the subsea rotating diverter. The constant SMP pressure during the first 10 seconds might be caused by the absence of the frictional pressure loss at the top of the well in this period. From the time 160 sec to 250, the SMP pressure increased with a constant rate. It is noticeable that the SMP in this case has been forced to operate in a constant flow rate mode and not in a constant inlet pressure mode as usual.

The conclusion of the simulation obtained here, is that the AUSMV scheme has proved an efficient ability in handling the SMD system. The well pressures have been increasing due that the mud volumes pumped in was higher than the mud volumes pumped out, and this was the expected result.

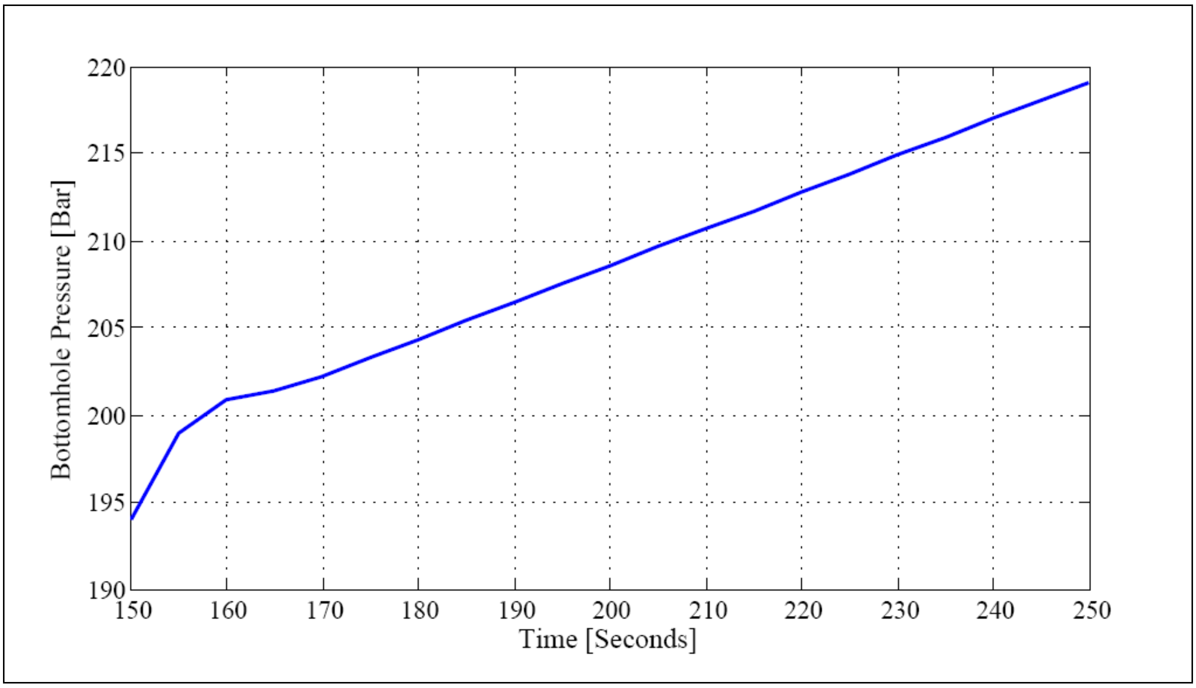

Figure 7.2: Bottomhole pressure development during the simulation of Case 1.

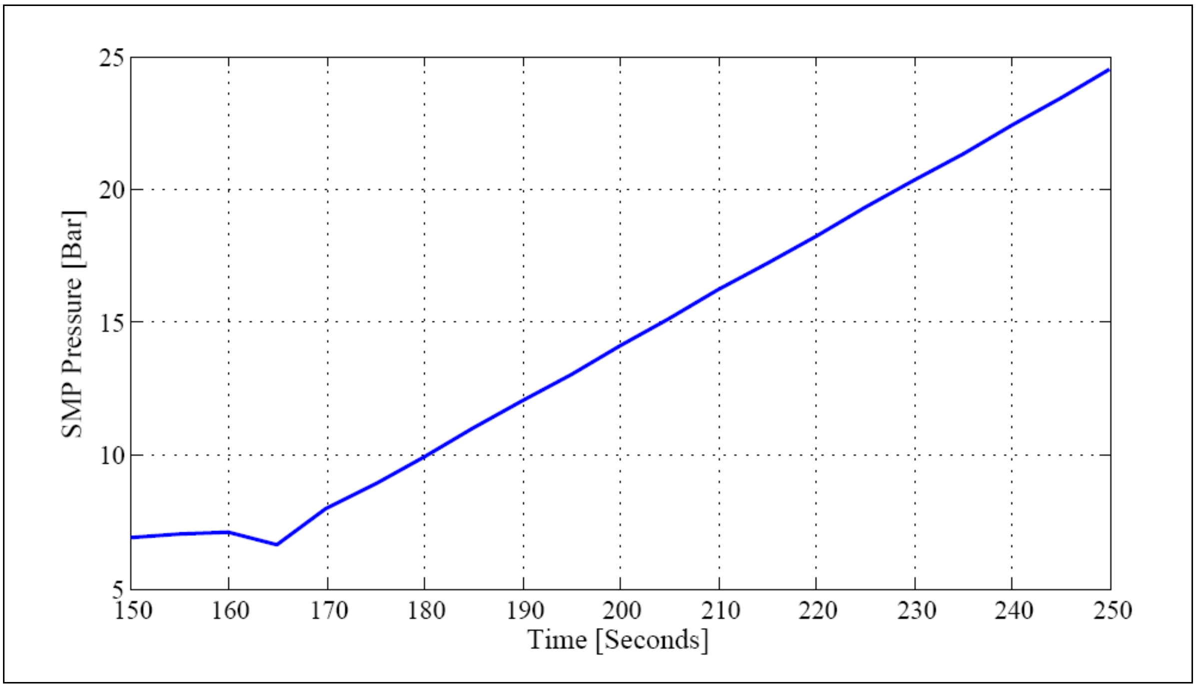

Figure 7.3: The pressure at the inlet of the subsea mudlift pump during the simulation of Case 1.

7.2 Case 2: SMD Kick Simulation

7.2.1 Test Background

The purpose of this simulation was to analyse the SMD system during a kick situation. Those types of simulations are important in order to understand the system, and to develop proper well control procedures, as the SMD is a new drilling concept and no sufficient well data is available today.

The test was constructed to take in a gas kick and observe the development of the different variables (e.g. fluid rates, gas fractions, pressures) during kick circulation. In the simulation of Case 2, more realistic conditions were fed in to the given AUSMV code. It is important to notice that during kick situation, there are two phases flowing through the well, which means that the boundary conditions should be given an additional care. In a two-phase flow system, two boundary conditions can be specified and one must be extrapolated at the inlet to system, and one boundary condition can be specified and two should be extrapolated at the outlet.

7.2.2 Extensions of the AUSMV Code

Several extensions of the AUSMV code were performed in this test. The purpose was to get a more realistic but still simple simulation of the SMD system during a gas kick situation. The most important extensions are listed below (for more details see the enclosed AUSMV code):

1) Well Geometry

The well geometry used in this test was as follows:

- Well depth = 2000 m.
- Water depth was approximately 2000 m.This was not specified in the AUSMV code directly but the pressure at the top of the well "surface pressure" was defined to be 200 bars which corresponds to approximately 2000 m high seawater colomn. In this case the well was assumed to be an offshore well in ultra deep water environment as the SMD system was developed to be used in such conditions.
- Well inclination = 0˚(Vertical well), A smart trick was used in the AUSMV code, the well was initially defined as a horizontal well with 90˚inclination and then it has been lifted up gradually during the first 100 seconds of simulation to get the initial conditions in the well prior to starting the injection of fluids at the bottom. Therefore any thing happened before the first 100 seconds will not be considered in the simulation results discussed below.
- Wellbore diameter = 0.2159 m, typical 8 1/2" section well, and the wellbore diameter was assumed to be constant throughout the whole 2000 m depth.
- Drillpipe diameter = 0.127 m, (or 5" drillpipe), this was again assumed to be constant throughout the whole well depth. This is again not realistic due to that BHA, drilling bit and connections have larger diameter than the rest of the drillpipe. This was assumed to make the simulation simpler. However the AUSMV scheme is designed to handle such flow area changes.

- The flow area was defined to be the annulus between the drillpipe and the wellbore: $Flow\ area = \frac{\pi}{4}(0.2159^2 - 0.127^2) = 0.0239\ m^2$
- Well opening was set to be 100 % (= 1), this has been changed to 0 % (= 0) due to the fact that the SMD system is a closed system where the Subsea Rotating Diverter seals the mud inside the wellbore from contact with sea water contained in the marine riser. The liquid massrate at the inlet of the subsea pump (outlet massrate) was specified as the physical boundary condition, while the outlet pressure and the outlet gas flux were found by extrapolation.

2) Fluid properties

Initial fluid properties were as presented in the following table:

Fluid Property	Liquid (Drilling Fluid)	Gas (Reservoir Fluid)
Density [kg/m^3]	1500 *	1.0
Viscosity [Pa s]	5 x 10^{-2}	5 x 10^{-6}
Sound Velocity in the Fluid [m/s]	1000	316

Table 7.3: Fluid properties used in the simulation of Case 2.

Fluid properties during the simulations were taken care of by the closure laws provided with the given AUSMV code. See chapter (5.2) for more details about closure laws.

* The initial liquid density was 1000 kg/m^3, this has been changed to 1500 kg/m^3 both in the main AUSMV code and in the corresponding liquid density code. The new liquid density gives better simulation to the reality as now weighted mud is used in the system and not water.

3) Boundary conditions treatment

The most important part of the simulation was to define the boundary conditions, as those are the main criteria that specify the type of the system. Six important variables were the key variables that have been modified to simulate the SMD system during the kick situation: inlet/outlet liquid massrates, inlet/outlet gas massrates, bottomhole pressure (inlet pressure) and pressure at the inlet of the Subsea Mudlift Pump (SMP) (outlet pressure). The outlet liquid/gas massrates were the liquid/gas massrate at the inlet of the SMP. All fluids flow took place after 150 seconds from the simulation start, and no fluid flow was initiated before that. The total simulation time was 5000 seconds. Table 7.4 presents the specified boundary conditions during the test. The remaining variables at the boundaries were found by extrapolation. More precisely the inlet/outlet liquid massrates and the inlet gas massrate were specified while the inlet and the outlet pressures and the outlet gas flux were extrapolated.

Time [Seconds]	Inlet Liquid Massrate (Mud) [kg/s]	Inlet Gas Massrate (Reservoir Fluid) [kg/s]	Outlet Liquid Massrate (Mud) [kg/s]
150 to 160	21.95*(time-150)/10	0	22*(time-150)/10
160 to 900	21.95	0	22
900 to 1000	21.95	4.0*(time-900)/100 or 0 *	22
1000 to 1020	22	0	22
1020 to 1060	22	0	23.5
1060 to 1900	22	0	22 or 23.5 **
1900 to 4300	22	0	21.75 or 23.5 **
4300 to 5000	22	0	22 or 23.5 **

Table 7.4: Fluid massrates used in the simulation of Case 2.

* The gas influx rate had two values during these 100 seconds due to that a criterion has been given to system to stop the gas influx when the bottomhole pressure exceeds 520 bars.

** The outlet massrates were alternating between two values after the kick occurred to keep the bottomhole pressure within a predefined safety margin (between 510 and 520 bars). This was done to compensate for pressure increase when the kick was circulated up in the well towards the outlet. When the outlet liquid massrate is larger than the inlet liquid massrate, the well pressures will decrease and oppositely.

The formation fracture pressure was assumed to be 530 bars at the bottom of the well, and the formations pore pressure was assumed to be 494 bars. This is a quite narrow margin formation, which simulates the condition that the SMD system is designed for.

7.2.3 Simulation Procedures of Case 2

The procedures used for the simulation of the SMD kick situation, were mainly taken from the Doctoral thesis of Handal [20]. The simulation procedures for Case 2 were as follows:

1) Normal drilling was taking place at the time between 160 sec to 900 sec, with slightly higher outlet mud massrate than the inlet mud massrate. This was mainly the reason for the kick occurrence, as the bottomhole pressure decreased gradually to be less than the pore pressure at that depth.
2) The kick occurred after the first 900 seconds, and the drilling has been stopped immediately. The flow massrates were kept constant equal to the rates that were used prior to taking the kick in order to allow the pressure to increase to stop the gas influx.
3) The bottomhole pressure increased rapidly to a predefined maximum (520 bars). This is due to gas inflow into a system where the outlet liquid massrate is fixed. Then the Subsea Mudlift Pump (SMP) rate has been adjusted to alternate between 22 to 23.5 kg/s to compensate for pressure increase caused by gas migration towards the outlet, and to keep the bottomhole pressure within the safety margin (between 510 to 520 bars) until the gas kick was out of hole.
4) When the gas was circulated out of hole, and a sufficient time has passed without detecting further gas influx, the drilling operations proceeded.

7.2.4 Simulation Results for Case 2

The following results have been obtained from the simulation of the SMD kick situation. Figure 7.4 below shows both bottomhole pressure and the pressure at the inlet of the Subsea Mudlift Pump (SMP) (hereinafter referred to as the SMP pressure), when the minimum outlet massrate was specified to be 18 kg/s. It is easy to observe that both pressures alternated rapidly within the safety margin (510 to 520 bars) when the gas reached the outlet of the well about 2500 second after the simulation began. This indicates that the minimum liquid massrate is too small causing rapid pressure alternation, when the outlet liquid massrate varied between 18 and 23 kg/s.

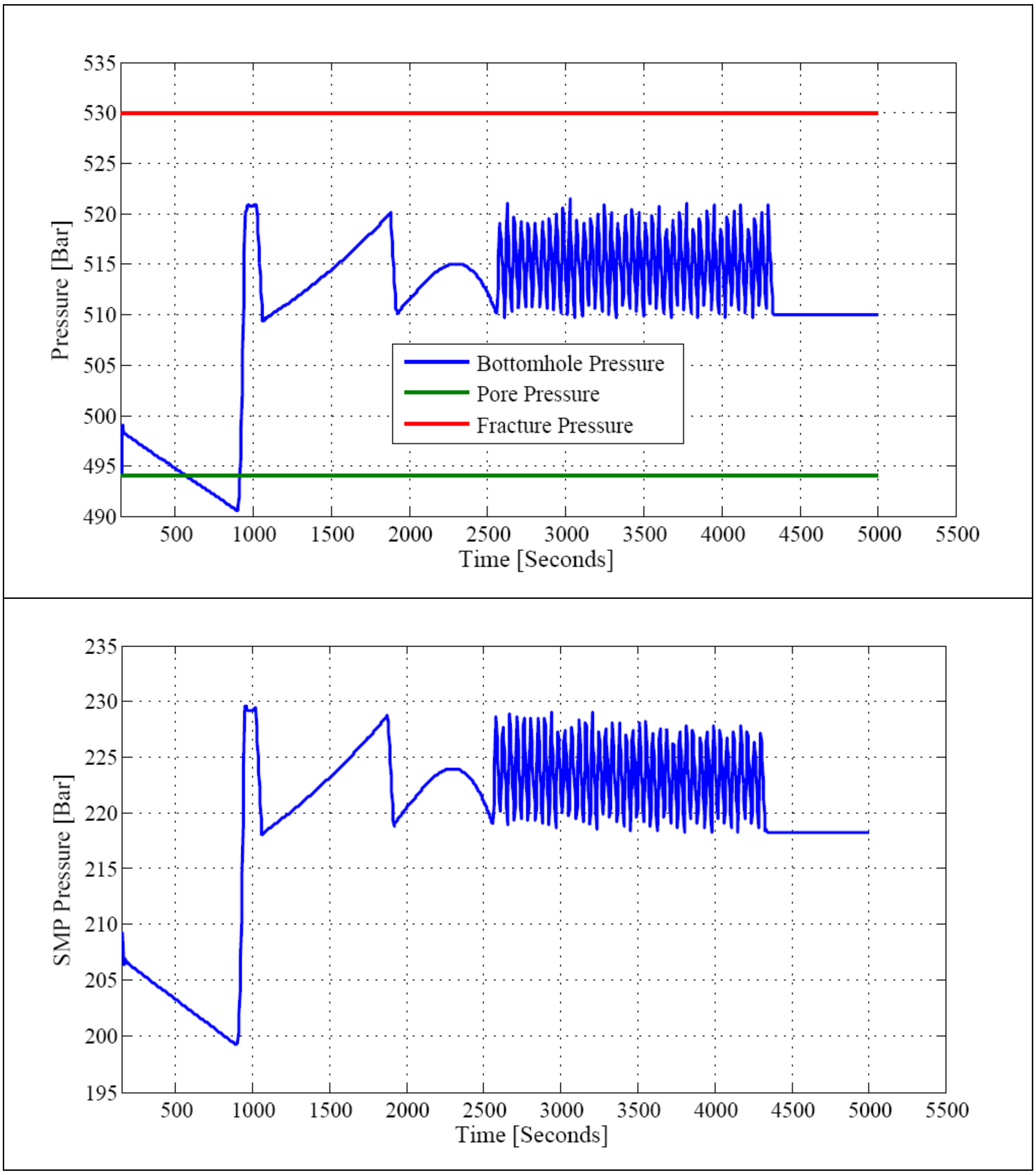

Figure 7.4: Bottomhole pressure (above) and SMP pressure (below) obtained by adjusting the minimum outlet massrate to 18 kg/s during kick circulation.

In Figure 7.5 below, bottomhole pressure and SMP pressure were obtained by using a minimum outlet massrate equal to 22 kg/s. In this case too much mud was sucked out of the system causing the well pressures to decrease quickly to be less than the pore pressure, which allows further gas influx from the formation. With such a large underbalanced situation, huge gas volumes can flow into the wellbore and the kick may develop into a serious blowout incident.

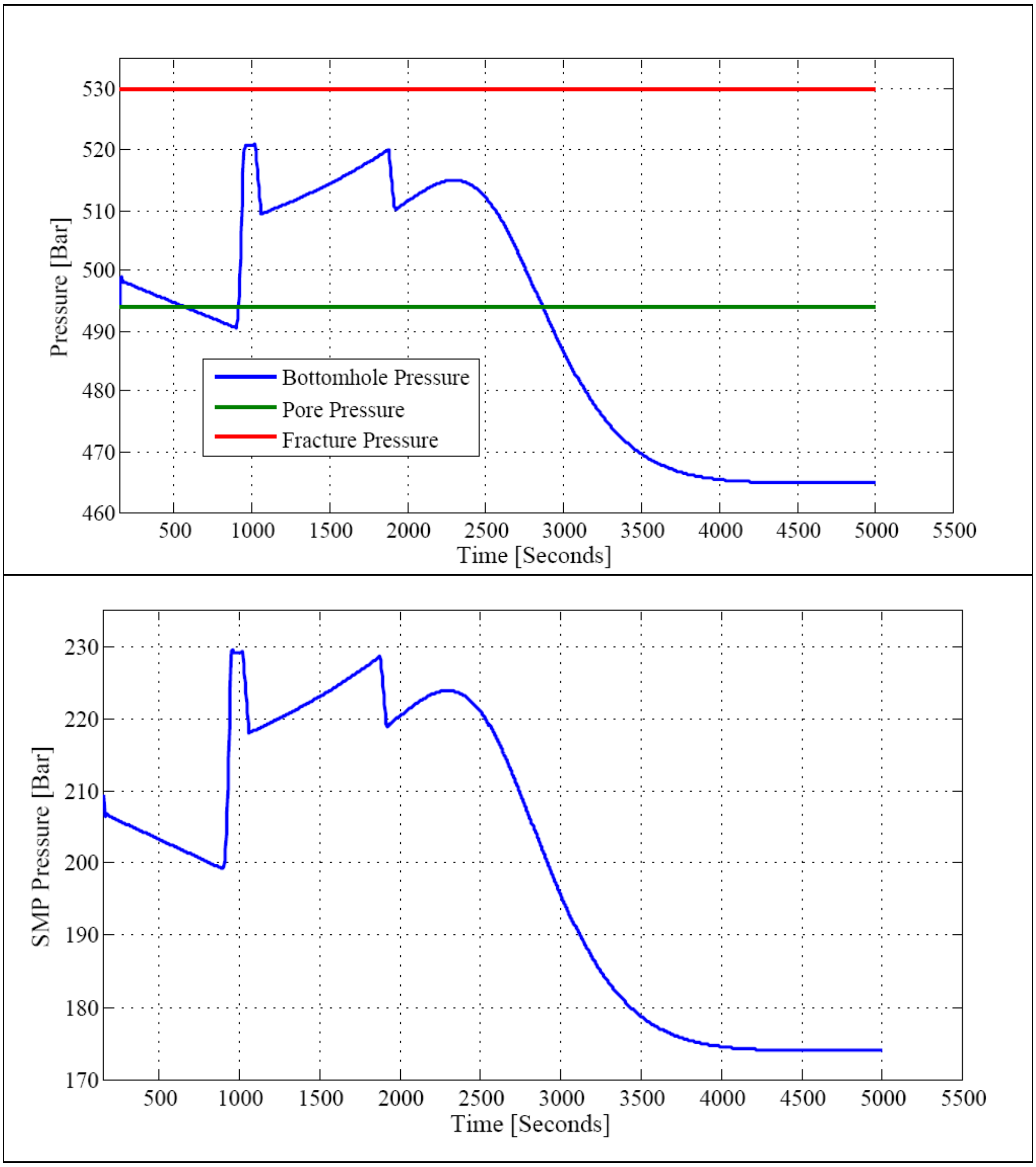

Figure 7.5: Bottomhole pressure (above) and SMP pressure (below) obtained by adjusting the minimum outlet massrate to 22 kg/s during kick circulation.

Figure 7.6 below shows the development of the bottomhole pressure and the SMP pressure during the kick situation, obtained when the minimum outlet massrate was specified to be 21.75 kg/s (Table 7.4). The first observation was that bottomhole pressure alternation was not very aggressive compared with the bottomhole pressure obtained by adjusting the minimum outlet massrate to 18 kg/s. The second observation was that bottomhole pressure was kept within the safety margin (between 510 and 520 bars). The SMP pressure developed exactly similarly to the bottomhole pressure. It is important to note that the SMP was not operating in a constant inlet pressure mode. The outlet massrate of 21.75 kg/s was more reasonable compared to the two minimum outlet massrates presented before. This minimum outlet massrate (21.75 kg/s) gave less well pressures alternation, and it kept the bottomhole pressure within the predefined safety margin. In addition there was no need to adjust the SMP rates up and down between the minimum outlet massrate of 21.75 kg/s and the maximum outlet massrate of 23 kg/s several times in short time steps. Therefore this minimum outlet massrate has been chosen to perform the rest of the simulations presented below.

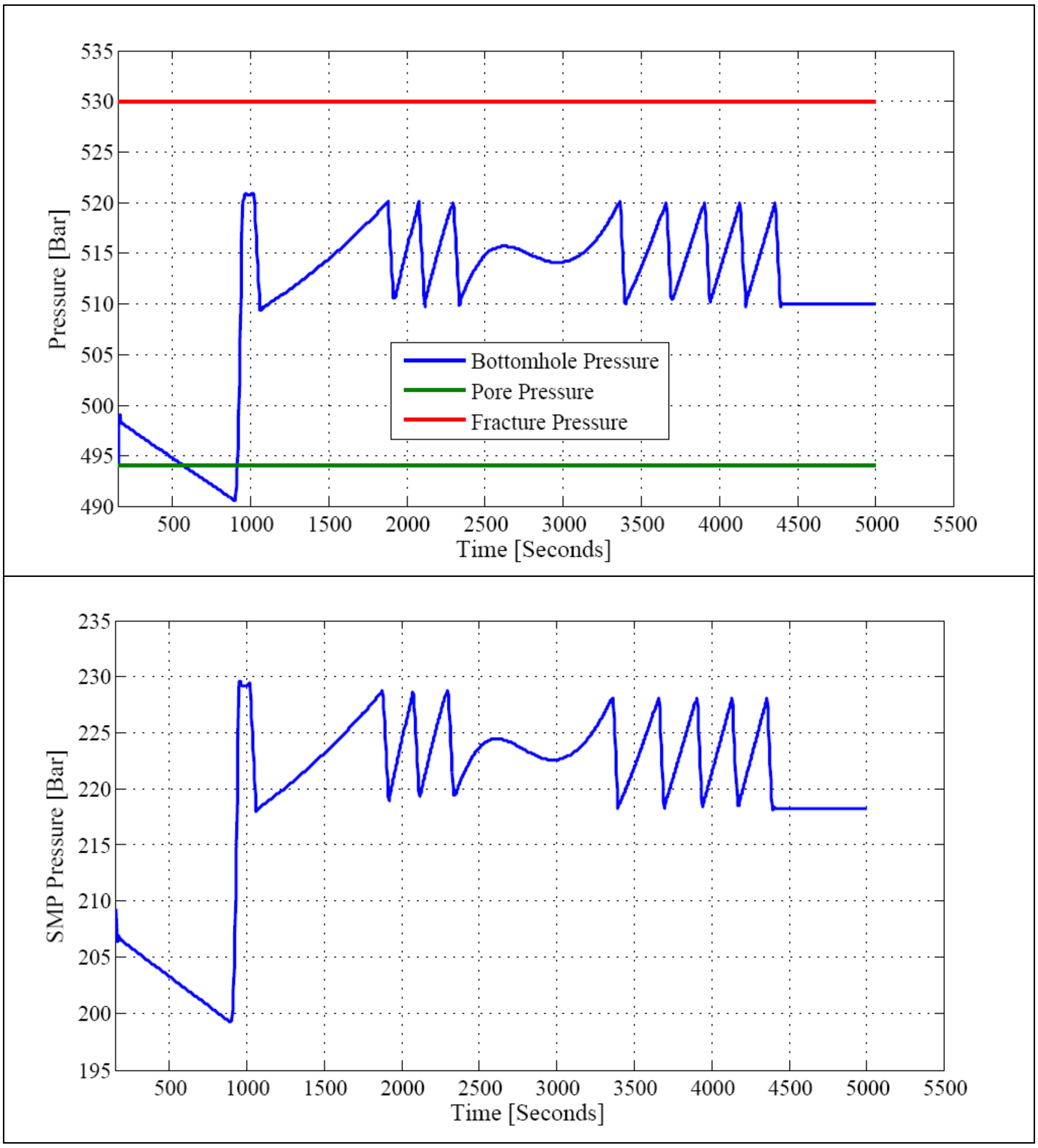

Figure 7.6: Bottomhole pressure (above) and SMP pressure (below) obtained by adjusting the minimum outlet massrate to 21.75 kg/s during kick circulation.

The inlet/outlet liquid massrates used in the simulations of the kick are presented in Figure 7.7. The inlet liquid massrate (the rate of the surface mud pump) was kept constant during kick occurrence and circulation. While the outlet liquid massrate (SMP rate) was adjusted several timed to compensate for pressure increase due to gas migration during kill circulation. An important observation is that the SMP can function as the conventional choke during kick situation as well pressures can be controlled by adjusting the SMP rate.

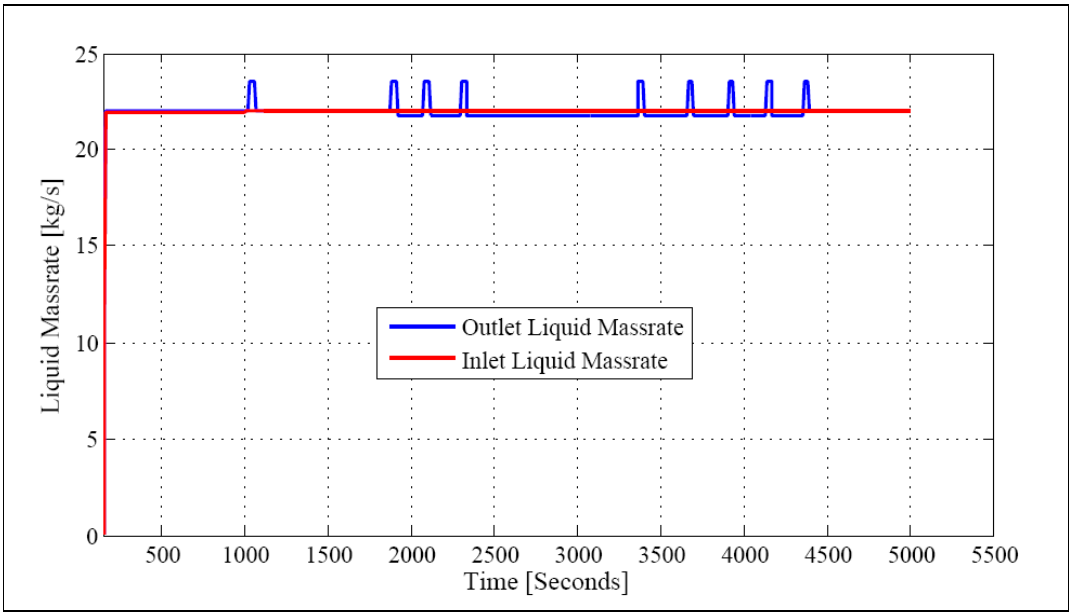

Figure 7.7: Inlet/outlet liquid massrates used in the simulation of the SMD kick.

The massrate of the gas influx is shown in Figure 7.8. The gas flowed into the wellbore during 50 seconds, after that the well pressure increased and further gas influx was eliminated. The maximum influx massrate was 1.8 kg/s, and the influx rate decreased rapidly after reaching the maximum.

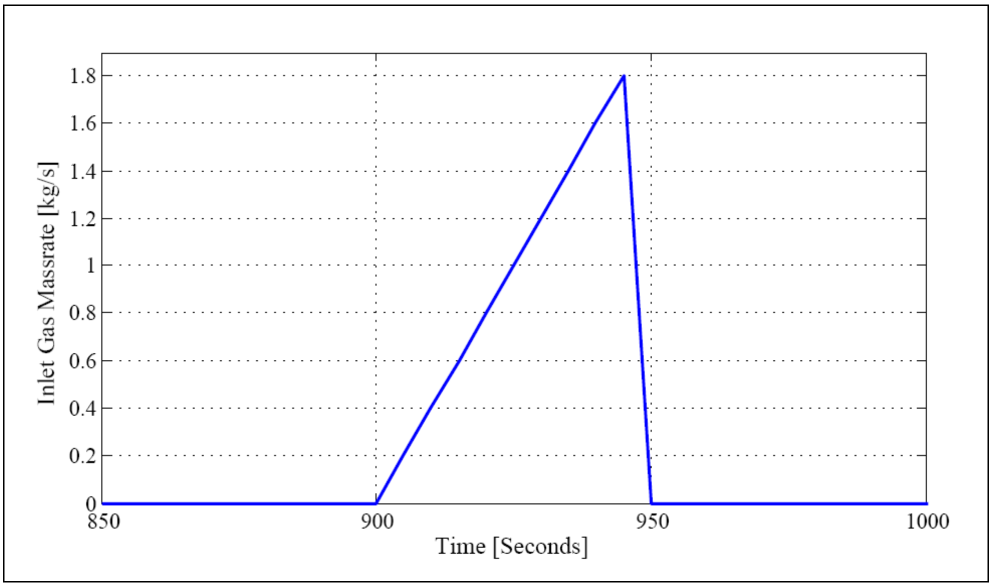

Figure 7.8: Gas influx massrate (kick rate).

Figure 7.9 below shows the development of the gas volume in the well. The total gas volume in the wellbore at the kick detection time was 0.1 m^3. Further increase in gas volume is due to gas expansion. After approximately 2200 seconds gas circulation has been initiated and consequently the gas volume decreased.

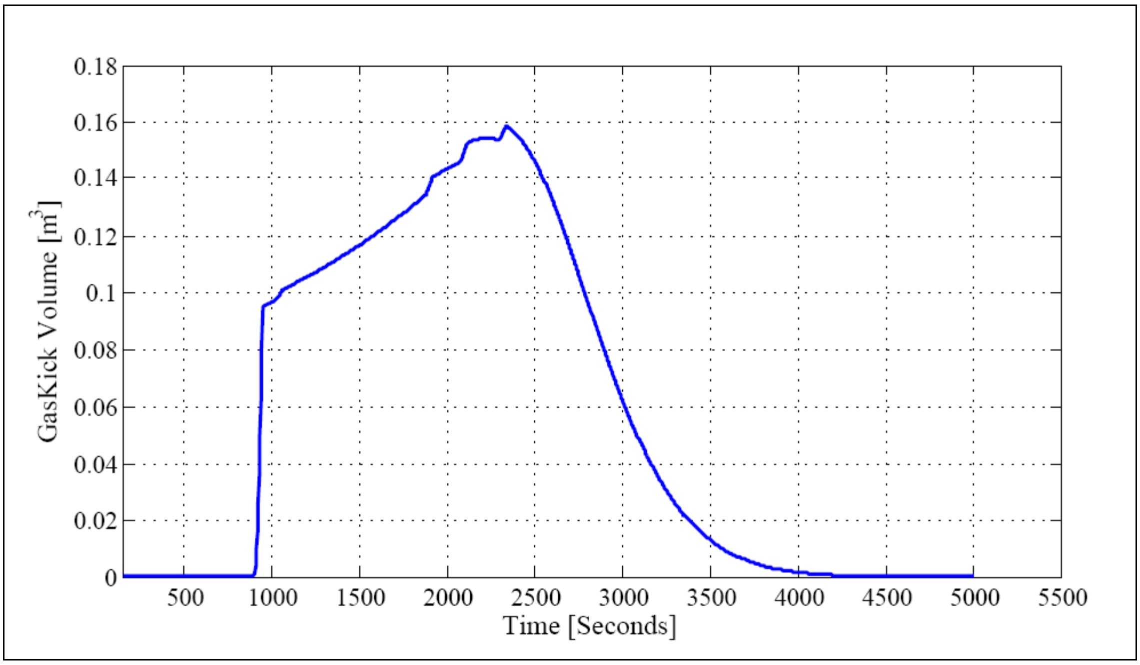

Figure 7.9: Total gas volume in the well during the kick circulation.

The outlet gas massrate is presented in Figure 7.10. The maximum gas rate was about 0.055 kg/s. The kick was totally out of the wellbore after approximately 4000 seconds.

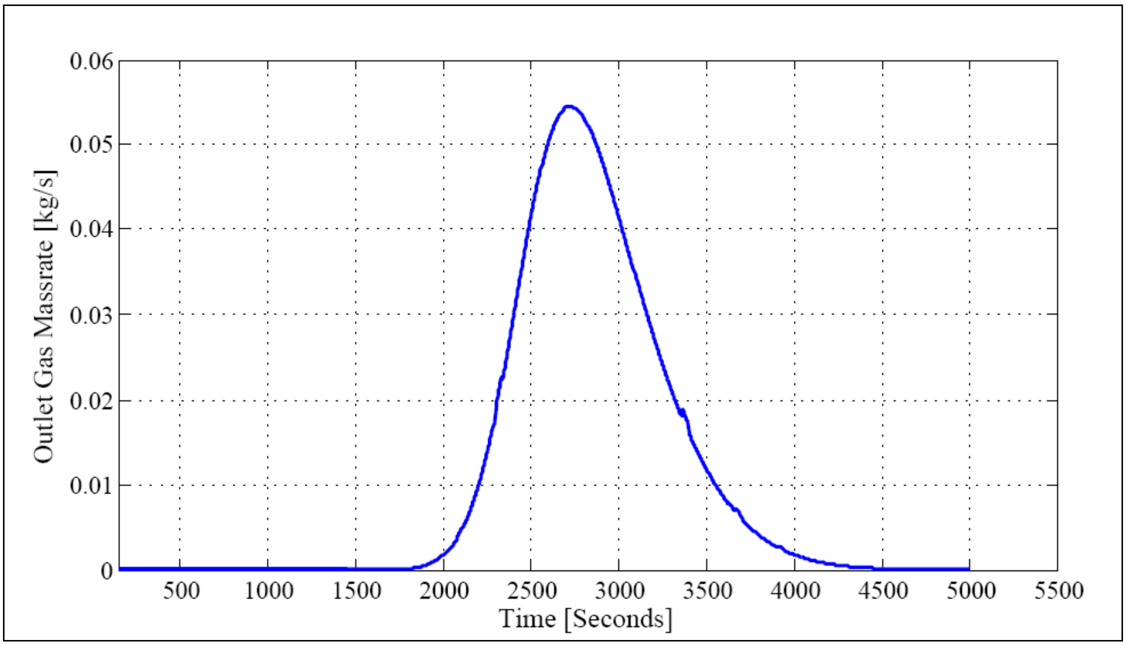

Figure 7.10: Outlet gas massrate during kick circulation.

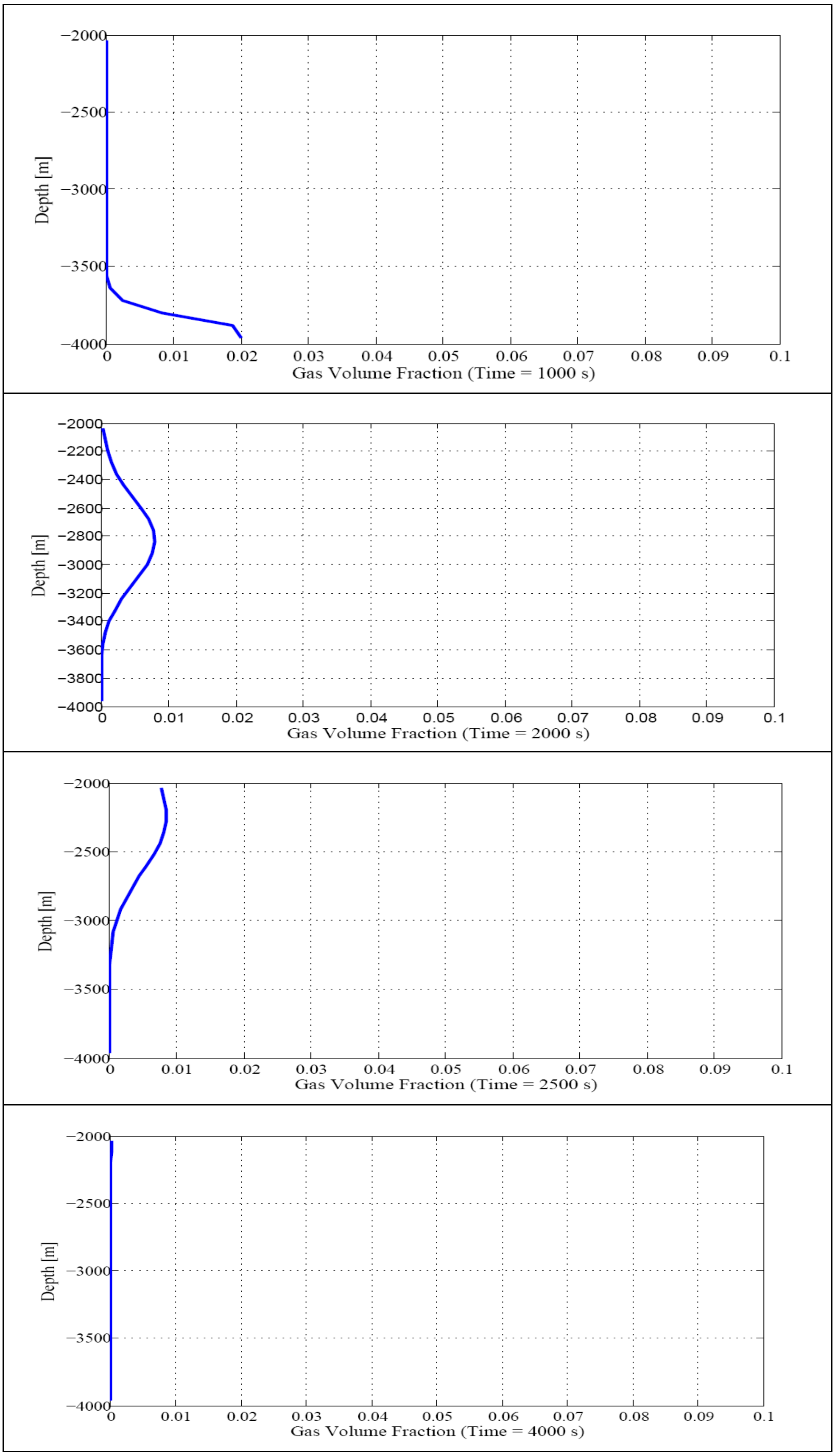

Figure 7.11: Gas volume fraction versus well depth captured at different simulation times.

Figure 7.11 above shows the gas volume fraction plotted versus well depth at different simulation times. The maximum gas volume fraction (0.02) was seen in the bottom of the well 1000 seconds after the simulation was started.

The conclusions obtained from this simulation are: First it was not necessary to increase the mud density after kick detection. The well pressures were controlled during and after the kick using the same mud density. The pressures were controlled by proper adjustments of the return pump rate. This is very beneficial for offshore drilling as weighting up the mud is an economically demanding and time and space consuming procedure. Secondly kick detection can be enhanced considerably by monitoring the SMP pressure. The third conclusion is that the Subsea Mudlift Pump (SMP) can be used as conventional choke to control well pressures during kick situation.

8 Conclusions

Dual Gradient Drilling (DGD) was proved to be reliable in providing solutions for the most of the drilling problems associated with deepwater and depleted offshore reservoirs. All field tests and the simulations performed to qualify this system have verified the robustness of these systems. Both the Subsea Mudlift Drilling (SMD) and the Low Riser Return System (LRRS) are ready to be used in drilling operations in the recent coming years. This can start a revolution in drilling technology and provide more evidences of the system robustness.

The following conclusions were drawn from the simulations of the SMD system:

- The AUSMV scheme is a simple but robust numerical method for analysing two-phase flow in one dimension. The scheme has the ability to be extended to simulate most cases of fluid flow in pipes or wells. However the corresponding models for fluid properties can be modified to include flow regimes, which give more accurate simulation of the real flow conditions. The AUSMV has provided good simulations of the SMD system compared with previous simulations of the same system performed by using other numerical approaches [20].
- The AUSMV scheme can handle variation in defining the boundary conditions. In this case the rates were specified at the boundaries while the pressures were extrapolated.
- When the inlet rate is larger than the outlet rate, the well pressure increases and oppositely.
- The simulation of the SMD kick situation showed that the minimum outlet rate (the rate of the Subsea Mudlift Pump (SMP)) during kick circulation must be chosen to be as accurate as possible, just small changes in the minimum outlet rate can affect the well pressure development considerably. In the simulation performed here the most suitable minimum outlet massrate was found to be 21.75 kg/s, while using a minimum outlet rate of 22 kg/s decreased the bottomhole pressure rapidly and brought the well into an underbalanced condition. When the minimum outlet rate was chosen to be 18 kg/s the well pressures alternated rapidly within the predefined safety margin, which means that the SMP rate must be adjusted up and down several times in short time steps.
- The SMP can not be operated in a constant inlet pressure mode during kick circulation as the SMP rate should be adjusted to compensate for pressure increase due to gas migration.
- Early kick detection is essential for proper well control. The simulations showed that kick detection can be enhanced considerably by monitoring the inlet pressure of the SMP.
- The SMP can function exactly as the conventional subsea choke as both are used to control well pressures during kick.
- A very important observation was that it was not necessary to increase the mud density after kick detection. The well pressures were controlled during and after the kick using the same mud density. This is very beneficial for offshore drilling if it is tested more and verified as weighting up the mud is an economically demanding and time and space consuming procedure.

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Appendices

Appendix 1

The AUSMV Code:

Note: The extensions made to the AUSMV code are marked with bold red font.

```
% Transient two-phase code based on AUSMV scheme: Gas and Water
% The code can handle area changes. The area changes are defined inside
% the cells such that the where the fluxes are calculated, the geometry is
% uniform.

clear;

% Geometry data/ Must be specified
welldepth = 2000;
nobox = 25; %Number of boxes in the well
nofluxes = nobox+1;
dx = welldepth/nobox; % Boxlength
%dt = 0.005;

% Welldepth array
x(1)= (-1.0*(welldepth+2000))+(0.5*dx);
for i=1:nobox-1
 x(i+1)=x(i)+ dx;
end

dt= 0.01;  % Timestep
dtdx = dt/dx;
time = 0.0;
endtime = 5000; % Rime for end of simulation
nosteps = endtime/dt;  %Number of total timesteps
timebetweensavingtimedata = 5;  % How often in s we save data vs time for
plotting.
nostepsbeforesavingtimedata = timebetweensavingtimedata/dt;

% Slip parameters used in the gas slip relation. vg =Kvmix+S
k = 1.2;
s = 0.5;

% Viscosities (Pa*s)/Used in the frictional pressure loss model.
viscl = 0.05; % Liquid phase
viscg = 0.000005; % Gas phase

% Density parameters. These parameters are used when finding the
% primitive variables pressure, densities in an analytical manner.
% Changing parameters here, you must also change parameters inside the
% density routines roliq and rogas.

% liquid density at stc and speed of sound in liquid
  dstc = 1500.0;  %Base density of liquid, See also roliq.
  pstc = 100000.0;
  al = 1000; % Speed of sound/compressibility of liquid phase.
```

```
  t1 = dstc-pstc/(al*al);
% Ideal gas law constant
  rt = 100000;

% Gravity constant

  grav = 9.81;

% Well opening. opening = 1, fully open well, opening = 0 (<0.01), the well
% is fully closed. This variable will control what boundary conditions that
% will apply at the outlet (both physical and numerical): We must change
% this further below in the code if we want to change status on this.

  wellopening = 1.0


% Specify if the primitive variables shall be found either by
% a numerical or analytical approach. If analytical = 1, analytical
% solution is used. If analytical = 0. The numerical approach is used.
% using the itsolver subroutine where the bisection numerical method
% is used.

  analytical = 1;


% Define and intilalize flow variables



% Check area: MERK HVORDAN VI KAN FORANDRE AREALET.
% Gemoetry below is 8.5" X 5" /typical 8 1/2" section well.

   for i = 1:nobox
    do(i) = 0.2159;
    di(i) = 0.127;
    areal(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
    arear(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
    area(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
    ang(i)=3.14/2;
   end

% The code below can be activated if one wants to introduce area changes
inside
% the well.
%     for i = 12:nobox-1
%      do(i)=0.1;
%      di(i)=0.0;
%      areal(i+1) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
%      arear(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
%      end
%     arear(nobox) = arear(nobox-1);



% Now comes the intialization of the physical variables in the well.
% First primitive variables, then the conservative ones.
    for i = 1:nobox
% Here the well is intialized. We start out with a horizontal well and
```

```
% lift this gradually up later during a 100 sec period to get the initial
% condtions in the well prior to starting the injection of fluids at the
% bottom. The extension letter o refers to the table represententing the
% values at the previous timestep (old values).

        % Density of liquid and gas:
        dl(i) = 1000.0;
        dg(i)= 1.0;
        %"Old" density is set equal to new density to calculate new values
        %based on the old ones:
        dlo(i)= dl(i);
        dgo(i)=dg(i);
        % Velocity of liquid and gas at new and previous timesteps:
        vl(i) = 0.0;
        vlo(i)= 0.0;
        vg(i)= 0.0;
        vgo(i)= 0.0;
        %The pressure in the horisontal pipe is the same
        %all over:
        p(i) = 100000.0;
        po(i) = p(i);
        %Phase volume fractions of gas and liquid:
        eg(i)= 0.0;    %Gas
        ego(i)=eg(i);
        ev(i)=1-eg(i); % Liquid
        evo(i)=ev(i);

        vg(i)=0.0;
        vgo(i)=0.0;
        vl(i)=0.0;
        vlo(i)=0.0;

        % Variables related to the velocity of the flux boundaries at old
        %and new times, and on the left and right side of the boxes
        % reflecting that area changes can take part inside cells (i.e :
        % (A x v)left = (A x v)right, continuity equation.
        vgr(i)=0.0;
        vgor(i)= 0.0;
        vgl(i)= 0.0;
        vgol(i)= 0.0;

        vlr(i)=0.0;
        vlor(i)=0.0;
        vll(i)=0.0;
        vlol(i)=0.0;

  % Conservative variables:

       qv(i,1)=dl(i)*ev(i)*(areal(i)+arear(i))*0.5;
       qvo(i,1)=qv(i,1);

       qv(i,2)=dg(i)*eg(i)*(areal(i)+arear(i))*0.5;
       qvo(i,2)=qv(i,2);

       qv(i,3)=(qv(i,1)*vl(i)+qv(i,2)*vg(i))*(areal(i)+arear(i))*0.5;
       qvo(i,3)=qv(i,3);

    end
```

```
% Intialize fluxes between the cells/boxes

for i = 1:nofluxes
  for j =1:3
   flc(i,j)=0.0; % Flux of liquid over box boundary
   fgc(i,j)=0.0; % Flux of gas over box boundary
   fp(i,j)= 0.0; % Pressure flux over box boundary
  end
end



%  Main program. Here we will progress in time. First som intializations
% and definitions to take out results. The for loop below runs until the
% simulation is finished.

countsteps = 0;
counter=0;
printcounter = 1;
pbot(printcounter) = p(1);
pchoke(printcounter)= p(nobox);
pcasingshoe(printcounter)=p(25);
ppore = 494;
pfrac = 530;
liquidmassrateout(printcounter) = 0;
gasmassrateout(printcounter)=0;
timeplot(printcounter)=time;

for i = 1:nosteps
   countsteps=countsteps+1;
   counter=counter+1;
   time = time+dt;

% First of all a dirty trick is used in order to make the well vertical.
% The pipe was initialised for a horisontal case. However, for a vertical
% case we would need a steady state solver. Since the programmer in this
% case is quite lazy, he rather chose to adjust the gravity constant g from
% zero to 9.81 m/s2 during 100 seconds (corresponds to hoisting the well
% from a horisontal postion to vertical case.

% If we want to simulate a horizontal well. Just comment/deactivate the
% code below.

       if (time <= 100)
         g = grav*time/100;
       else
         g = grav;
       end



% Then a section where specify the boundary conditions.
% Here we specify the inlet rates of the different phases at the
% bottom of the pipe in kg/s. We interpolate to make things smooth.
% It is also possible to change the outlet boundary status of the well
% here. First we specify rates at the bottom and the pressure at the outlet
% in case we have an open well.
```

```
% The code below is an example of an open connection

if (time < 150)

  inletligmassrate=0.0;
  inletgasmassrate=0.0;
  save = 0;

elseif ((time>=150) & (time < 160))
  inletligmassrate = 21.95*(time-150)/10;
  inletgasmassrate = 0;
  outletrate = 22*(time-150)/10;
  save = outletrate;
elseif ((time >=160) & (time<900))
   inletligmassrate = 21.95;
   inletgasmassrate = 0;
   outletrate = 22;
   wellopening = 0;
   save = outletrate;
elseif ((time >=900) & (time<1000))
   inletligmassrate = 21.95;
   inletgasmassrate = 4.0*(time-900)/100;

   if (p(1)>52000000)
      inletgasmassrate= 0;
   end

   outletrate = 22;
   wellopening = 0;
   save = outletrate;
elseif ((time >=1000) & (time<1020))
   inletligmassrate = 22;
   inletgasmassrate = 0;
   outletrate = 22;
   wellopening = 0;
   save = outletrate;
elseif ((time >=1020) & (time<1060))
   inletligmassrate = 22;
   inletgasmassrate = 0;
   outletrate = 23.5;
   wellopening = 0;
   save = outletrate;
elseif ((time >=1060) & (time<1900))
   inletligmassrate = 22;
   inletgasmassrate = 0;

   if (p(1)<=51000000)
      outletrate = 22;
   elseif (p(1)>52000000)
      outletrate = 23.5;
   end
```

```
  wellopening = 0;
  save = outletrate;
elseif ((time >=1900) & (time<4300))
  inletligmassrate = 22;
  inletgasmassrate = 0;

  if (p(1)<=51000000)
    outletrate = 21.75;
  elseif (p(1)>52000000)
    outletrate = 23.5;
  end

  wellopening = 0;
  save = outletrate;
elseif ((time >=4300) & (time<5000))
  inletligmassrate = 22;
  inletgasmassrate = 0;

  if (p(1)<=51000000)
   outletrate = 22;
  elseif (p(1)>52000000)
    outletrate = 23.5;
  end

  wellopening = 0;
  save = outletrate;
else
 inletligmassrate= 22;
 inletgasmassrate= 0;
 save = outletrate;
end


% Below, test code for onephase connection. Commented out. Friction
% model seems reasonable.
% if (time < 150)
%
%   inletligmassrate=0.0;
%   inletgasmassrate=0.0;
%
% elseif ((time>=150) & (time < 160))
%   inletligmassrate = 44*(time-150)/10;
%   inletgasmassrate = 0;
%
% elseif ((time >=160) & (time<300))
%   inletligmassrate = 44;
%   inletgasmassrate = 0;
%
% elseif ((time>=300)& (time<310))
%   inletligmassrate = 44-44*(time-300)/10;
%   inletgasmassrate = 0;
% else
%   inletligmassrate=0;
```

```
%   inletgasmassrate = 0;
% end




% specify the outlet pressure /Physical. Here we have given the pressure as
% constant. It would be possible to adjust it during openwell conditions
% either by giving the wanted pressure directly (in the command lines
% above) or by finding it indirectly through a chokemodel where the
wellopening
% would be an input parameter. The wellopening variable would equally had
% to be adjusted inside the command line structure given right above.

 pressureoutlet = 20000000.0;

% Based on these boundary values combined with use of extrapolations
techniques
% for the remaining unknowns at the boundaries, we will define the mass and
% momentum fluxes at the boundaries (inlet and outlet of pipe).

% inlet fluxes first.

     flc(1,1)= inletligmassrate/areal(1);
     flc(1,2)= 0.0;
     flc(1,3)= flc(1,1)*vlo(1);

     fgc(1,1)= 0.0;
     fgc(1,2)= inletgasmassrate/areal(1);
     fgc(1,3)= fgc(1,2)*vgo(1);

     fp(1,1)= 0.0;
     fp(1,2)= 0.0;
     fp(1,3)= po(1)+0.5*(po(1)-po(2)); %Interpolation used to find the
% pressure at the inlet/bottom of the well.



% Outlet fluxes (open & closed conditions)

    if (wellopening>0.01)
        flc(nofluxes,1)= dlo(nobox)*evo(nobox)*vlo(nobox);
        flc(nofluxes,2)= 0.0;
        flc(nofluxes,3)= flc(nofluxes,1)*vlo(nobox);

        fgc(nofluxes,1)= 0.0;
        fgc(nofluxes,2)= dgo(nobox)*ego(nobox)*vgo(nobox);
        fgc(nofluxes,3)= fgc(nofluxes,2)*vgo(nobox);

        fp(nofluxes,1)= 0.0;
        fp(nofluxes,2)= 0.0;
        fp(nofluxes,3)= pressureoutlet;
    else


         flc(nofluxes,1)= outletrate/area(nobox);
         flc(nofluxes,2)= 0.0;
```

```
        flc(nofluxes,3)= 0.0;

        fgc(nofluxes,1)= 0.0;
    %     fgc(nofluxes,2)= 0.0;
        fgc(nofluxes,2)= dgo(nobox)*ego(nobox)*vgo(nobox);
    %     fgc(nofluxes,3)= 0.0;
        fgc(nofluxes,3)= fgc(nofluxes,2)*vgo(nobox);

        fp(nofluxes,1)=0.0;
        fp(nofluxes,2)=0.0;
        fp(nofluxes,3)= po(nobox)-0.5*(po(nobox-1)-po(nobox));

    end

% Now we will find the fluxes between the different cells.
% NB - IMPORTANE -  Note that if we change the compressibilities/sound
velocities of
% the fluids involved, we need to do changes inside the csound function.

     for j = 2:nofluxes-1
      cl = csound(ego(j-1),po(j-1),dlo(j-1),k);
      cr = csound(ego(j),po(j),dlo(j),k);
      c = max(cl,cr);
      pll = psip(vlor(j-1),c,evo(j));
      plr = psim(vlol(j),c,evo(j-1));
      pgl = psip(vgor(j-1),c,ego(j));
      pgr = psim(vgol(j),c,ego(j-1));
      vmixr = vlol(j)*evo(j)+vgol(j)*ego(j);
      vmixl = vlor(j-1)*evo(j-1)+vgor(j-1)*ego(j-1);

      pl = pp(vmixl,c);
      pr = pm(vmixr,c);
      mll= evo(j-1)*dlo(j-1);
      mlr= evo(j)*dlo(j);
      mgl= ego(j-1)*dgo(j-1);
      mgr= ego(j)*dgo(j);

      flc(j,1)= mll*pll+mlr*plr;
      flc(j,2)= 0.0;
      flc(j,3)= mll*pll*vlor(j-1)+mlr*plr*vlol(j);

      fgc(j,1)=0.0;
      fgc(j,2)= mgl*pgl+mgr*pgr;
      fgc(j,3)= mgl*pgl*vgor(j-1)+mgr*pgr*vgol(j);

      fp(j,1)= 0.0;
      fp(j,2)= 0.0;
      fp(j,3)= pl*po(j-1)+pr*po(j);
     end

% Fluxes have now been calculated. We will now update the conservative
% variables in each of the numerical cells.



     for j=1:nobox

%      vmixfric = vlo(j)*evo(j)+vgo(j)*ego(j); % Mixture viscosity
```

```
%       viscmix =  viscl*evo(j)+viscg*ego(j);
      densmix = dlo(j)*evo(j)+dgo(j)*ego(j);

      a2 = arear(j);
      a1 = areal(j);
      avg = (a2+a1)*0.5;

      pressure=p(j);

%     We calculate the frictional gradient by calling upon the dpfric
function.
      friclossgrad =
dpfric(vlo(j),vgo(j),evo(j),ego(j),dlo(j),dgo(j),pressure,do(j),di(j),viscl
,viscg);


%     Here is the updating of the conservative variables/where we solve the
%     two mass conservation equations and the third momentum equation.
      qv(j,1)=qvo(j,1)-dtdx*((a2*flc(j+1,1)-a1*flc(j,1))...
                      +(a2*fgc(j+1,1)-a1*fgc(j,1))...
                      +(avg*fp(j+1,1)-avg*fp(j,1)));

      qv(j,2)=qvo(j,2)-dtdx*((a2*flc(j+1,2)-a1*flc(j,2))...
                      +(a2*fgc(j+1,2)-a1*fgc(j,2))...
                      +(avg*fp(j+1,2)-avg*fp(j,2)));

      qv(j,3)=qvo(j,3)-dtdx*((a2*flc(j+1,3)-a1*flc(j,3))...
                      +(a2*fgc(j+1,3)-a1*fgc(j,3))...
                      +(avg*fp(j+1,3)-avg*fp(j,3)))...
             -dt*avg*((friclossgrad)+g*densmix);
     end

     %Simple friction model for only pipe/laminar flow:
     %(32*vmixfric*viscmix/(do(j)*do(j))+g*densmix);



% Section where we find the physical variables (pressures, densities etc)
% from the conservative variables. Some trickes to ensure stability

     V = 0;
     for j=1:nobox


% Remove the area from the conservative variables to find the
% the primitive variables from the conservative ones.

      qv(j,1)= qv(j,1)/(areal(j)+arear(j))*2.0;
      qv(j,2)= qv(j,2)/(areal(j)+arear(j))*2.0;

      if (qv(j,1)<0.00000001)
        qv(j,1)=0.0;
      end

      if (qv(j,2)< 0.00000001)
        qv(j,2)=0.0000001;
      end
```

```
% Below, we find the primitive variables pressure and densities based on
% the conservative variables q1,q2. One can choose between getting them by
% analytical or numerical solution approach specified in the beginning of
% the program.

    if (analytical == 1)
      % Coefficients:
      a = 1/(al*al);
      b = t1-qv(j,1)-rt*qv(j,2)/(al*al);
      c = -1.0*t1*rt*qv(j,2);

      % Analytical solution:
       p(j)=(-b+sqrt(b*b-4*a*c))/(2*a);  % Pressure
       dl(j)= dstc + (p(j)-pstc)/(al*al); % Density of liquid
       dg(j) = p(j)/rt;                   % Density of gas
    else
      %Numerical Solution:
      [p(j),error]=itsolver(po(j),qv(j,1),qv(j,2)); % Pressure
      dl(j)=rholiq(p(j)); % Density of liquid
      dg(j)=rogas(p(j)); % Density of gas

      % Incase a numerical solution is not found, the program will write
out "error":
      if error > 0
         error
      end
    end


 % Find the phase volume fractions based on new conservative variables and
 % updated densities.

      eg(j)= qv(j,2)/dg(j);
      ev(j)=1-eg(j);

      V = V+dx*area(j)*eg(j);

%     Reset average conservative varibles in cells with area changes
inside.

      qv(j,1)=qv(j,1)*(areal(j)+arear(j))/2.0;
      qv(j,2)=qv(j,2)*(areal(j)+arear(j))/2.0;


%     The section below is used to find the primitive variables vg,vl
%    (phase velocities) based on the updated conservative variable q3 and
%     the slip relation.

%      Deactivated code below, old code for no slip cond & no area change.
%      vg(j)=qv(j,3)/(dl(j)*ev(j)+dg(j)*eg(j));
%      vl(j)=vg(j);

% Part where we interpolate in the slip parameters to avoid a
% singularities when approaching one phase gas flow.
% In the transition to one-phase gas flow, we need to
% have a smooth transition to no-slip conditions.
```

```
      xint = (eg(j)-0.75)/0.25;
      k0 = k;
      s0 = s;
      if ((eg(j)>=0.75) & (eg(j)<=1.0))
        k0 =1.0*xint+k*(1-xint);
        s0 = 0.0*xint+s*(1-xint);
      end

      if (eg(j)>=0.999999)
        k1 = 1.0;
        s1 = 0.0;
      else
        k1 = (1-k0*eg(j))/(1-eg(j));
        s1 = -1.0*s0*eg(j)/(1-eg(j));
      end
 %     help1 = dl(j)*ev(j)*k1+dg(j)*eg(j)*k0;
 %     help2 = dl(j)*ev(j)*s1+dg(j)*eg(j)*s0;

 %     vmixhelp = (qv(j,3)-help2)/help1;
 %     vg(j)=k0*vmixhelp+s0;
 %     vl(j)=k1*vmixhelp+s1;
%       help1 = qv(j,3)/(dl(j)*ev(j)+dg(j)*eg(j));
%
%       vll(j)= help1/areal(j);
%       vlr(j)= help1/arear(j);
%       vgl(j)= vll(j);
%       vgr(j)= vlr(j);


 %    Below we operate with gas vg and liquid vl velcoities specified
 %    both in the right part and left part inside a box. (since we have
 %    area changes inside a box these can be different. vgl is gas velocity
 %    to the left of the disconinuity. vgr is gas velocity to the right of
 %    the discontinuity.
 %

      help1 = dl(j)*ev(j)*k1+dg(j)*eg(j)*k0;
      help2 = dl(j)*ev(j)*s1+dg(j)*eg(j)*s0;

      vmixhelpl = (qv(j,3)/areal(j)-help2)/help1;
      vgl(j)=k0*vmixhelpl+s0;
      vll(j)=k1*vmixhelpl+s1;

      vmixhelpr = (qv(j,3)/arear(j)-help2)/help1;
      vgr(j)=k0*vmixhelpr+s0;
      vlr(j)=k1*vmixhelpr+s1;

 %  Averaging velocities.

      vl(j)= 0.5*(vll(j)+vlr(j));
      vg(j)= 0.5*(vgl(j)+vgr(j));

    end



% Old values are now set equal to new values in order to prepare
% computation of next time level.
```

```
    for j = 1:nobox
     po(j)=p(j);
     dlo(j)=dl(j);  %Liquid density
     dgo(j)=dg(j);  %Gas density
     vlo(j)=vl(j);  %Liquid velocity
     vgo(j)=vg(j);  %Gas velocity
     ego(j)=eg(j);  %Gas fration
     evo(j)=ev(j);  %Liquid fraction.

     vlor(j)=vlr(j);
     vlol(j)=vll(j);
     vgor(j)=vgr(j);
     vgol(j)=vgl(j);

      for m =1:3
       qvo(j,m)=qv(j,m);
      end
    end


% Section where we save some timedependent variables in arrays.
% e.g. the bottomhole pressure. They will be saved for certain
% timeintervalls defined in the start of the program in order to ensure
% that the arrays do not get to long!

  if (counter>=nostepsbeforesavingtimedata)
    printcounter=printcounter+1;
    time
    pbot(printcounter)= p(1);
    pchoke(printcounter)=p(nobox);
    ppore(printcounter) = 494;
    pfrac(printcounter) = 530;
    pcasingshoe(printcounter)=p(25); %NB THIS MUST BE DEFINED IN CORRECT
BOX
%
liquidmassrateout(printcounter)=dl(nobox)*ev(nobox)*vl(nobox)*area(nobox);
%
gasmassrateout(printcounter)=dg(nobox)*eg(nobox)*vg(nobox)*area(nobox);
%
liquidmassrateout(printcounter)=dl(nobox)*ev(nobox)*vl(nobox)*arear(nobox);
    liquidmassrateout(printcounter)=save;

gasmassrateout(printcounter)=dg(nobox)*eg(nobox)*vg(nobox)*arear(nobox);
    liquidmassratein (printcounter)=inletligmassrate;
    gasmassratein (printcounter)=inletgasmassrate;
    timeplot(printcounter)=time;

    if (time < 100)
    V = 0;
    end

    kickvolume(printcounter)=V;
    counter = 0;


  end
end
```

```
% end of stepping forward in time.




% Printing of resultssection


countsteps % Marks number of simulation steps.


% Plot commands for variables vs time.
%plot(timeplot,pbot/100000,timeplot,ppore,timeplot,pfrac)
%plot(timeplot,pchoke/100000)
%plot(timeplot,pcasingshoe/100000)
%plot(timeplot,liquidmassrateout)
%plot(timeplot,gasmassrateout)
%plot(timeplot,liquidmassratein)
%plot(timeplot,gasmassratein)
%plot(vg)

%Plot commands for variables vs depth/Only the last simulated
%values/endtime is visualised

%plot(vl,x);
%plot(vg,x);
plot(eg,x)
%plot(p,x);
%plot(dl,x);
%plot(dg,x);
```

Appendix 2

The Liquid Density Code:

Note: The extensions made to the liquid density code are marked with bold red font.

```
function [rhol] = rholiq(pressure)
%Simple model for liquid density
p0 = 100000.0; % Assumed

rhol = 1500.0 + (pressure-p0)/(1000.0*1000.0);
end
```