University of Stavanger

**Faculty of Science and Technology**

# MASTER'S THESIS

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# I. Abstract

Managed Pressure Drilling (MPD) is a relatively young technology that has improved some old ideas of Underbalanced Drilling (UBD). According to the IADC, MPD is an “adaptive process used to precisely control the annular pressure profile throughout the wellbore. The goal is to ascertain the downhole pressure environment limits and to manage the annular pressure profile accordingly”. In other words the main aim of MPD is to avoid continuous influx of formation fluids to the surface by maintaining a state of effective overbalance. It’s done by applying surface backpressure during drilling ahead or shut-in to make a connection of jointed pipe. Basic tools required to conduct MPD are: a rotating control device (RCD), drillstring non-return valves and dedicated choke manifold. MPD allows drilling through the un-drillable in conventional way formations, helps to reduce non productive time (NPT) and to overcome several drilling problems like: drilling with narrow “pressure window” and kick-loss scenarios caused by narrow margins, excessive casing program, low ROP, excessive mud cost caused by the loss of circulation, failure to reach TD with large enough hole diameter and shallow geohazards both with drilling riserless and with casing or marine riser. This technology enables manage pressures through the wellbore in more precise way than conventional drilling and there are several strong indicators that MPD in marine environments will be a breakthrough technology in offshore industry in the next years. It’s a big chance for MPD to be best solution for drilling in reservoirs with narrow pressure window, drilling with troublesome zones, depleted reservoirs, HP/HT reservoirs and to overcome almost all offshore drilling-related challenges. Therefore the main objective of this Master’s Thesis is to evaluate both technical and economical feasibility of using Managed Pressure Drilling technology from a floating drilling rig on the Skarv/Idun field on the NCS. Furthermore to show which MPD variation is most suitable on this field, equipment needed to conduct MPD operations, evaluates reservoir and drilling related benefits and assess which drilling problems can be avoided using Managed Pressure Drilling technology.

## II. Dedication

This thesis is dedicated to my parents for all their support and encouragement throughout the years.

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# IV. Table of Contents

**I. Abstract**

**II. Dedication**

**III. Acknowledgments**

**IV. Table of Contents**

**V. List of Tables**

**VI. List of Figures**

**VII. Objective**

**1. Introduction**

- 1.1. Basic principles of Managed Pressure Drilling
- 1.2. Advantages and Methods of Managed Pressure Drilling
- 1.3. Managed Pressure Drilling variations
  - 1.3.1. Constant Bottom-hole Pressure
  - 1.3.2. HSE MPD
  - 1.3.3. Deepwater Dual-gradient MPD
  - 1.3.4. Pressurized Mud Cap Drilling
  - 1.3.5. Riserless MPD
  - 1.3.6. Zero Discharge Riserless (Dual Gradient Riserless) MPD
  - 1.3.7. Reelwell Drilling Method
- 1.4. Managed Pressure Drilling – basic tools
  - 1.4.1. Rotating Control Devices and Rotating Annular Preventers
  - 1.4.2. Chokes
  - 1.4.3. Non-Return Valves
- 1.5. Managed Pressure Drilling – other tools
  - 1.5.1. Downhole Deployment Valves
  - 1.5.2. ECD Reduction Tool
  - 1.5.3. Coriolis Flow Meter
  - 1.5.4. Downhole Air Diverter
  - 1.5.5. Nitrogen Generation Unit
  - 1.5.6. Multiphase Separation System

1.5.7. Real-time Pressure and Flowrate Monitoring

1.5.8. Continuous Circulation Valve

1.5.9. Continuous Circulation System

1.6. Demand for Managed Pressure Drilling in marine environments

1.7. Offshore Underbalanced Drilling vs. Managed Pressure Drilling

**2. Managed Pressure Drilling from floating platforms**

2.1. Heave compensation and station keeping

2.2. Placement of Rotating Control Device

2.2.1. Install the RCD above the Slipjoint with the Slipjoint collapsed and locked

2.2.2. Install the RCD above the Slipjoint with the Slipjoint inner barrel removed

2.2.3. Install the RCD below the tension ring and Slipjoint

2.2.4. Install the RCD at the Subsea stack below the LMRP

2.2.5. Install the BOP stack with the RCD installed at surface

2.3. Surge and swab effect during making connections

2.4. Excessive casing strings

2.5. U-Tube effects in Managed Pressure Drilling operations

2.6. Wellbore control

2.7. Annular pressure changes (ECD problems)

2.8. Wellbore ballooning

2.9. Time to detect influx

2.10. Recent experiences with MPD from floaters

**3. Review of the Skarv/Idun field development**

3.1. Overview of the Skarv/Idun field development

3.1.1. Field development concept

3.1.2. Regional geological setting

3.1.3. Geology prognosis

3.1.4. Wells and wellbore trajectories

3.1.5. Pore pressures, temperature and fracture gradients

3.1.6. Casing design

3.1.7. Templates and Manifolds

3.1.8. Flowlines and Risers

3.1.9. Host

3.2. Production Geology and Geophysics

3.2.1. Seismic data and interpretation

3.2.2. Stratigraphy and characteristic of the reservoir

3.2.3. Compartments and fluid contact

3.3. Production strategy and production profiles

3.3.1. Fluid properties and initial reservoir conditions

3.3.2. Recoverable resources

3.3.3. Reservoir simulation

**4. Review of the Transocean's Polar Pioneer semi-submersible drilling rig**

4.1. General information and technical dimensions

4.2. Storage capacities and marine equipment

4.3. Drilling and subsea/well control equipment

**5. Application of Managed Pressure Drilling on the Skarv/Idun field**

5.1. Managed Pressure Drilling candidate selection

5.1.1. Hydraulic analysis

5.1.2. Method selection / viability of the options

5.1.3. Special Drilling Equipment

5.1.4. HAZOP and HAZID

5.2. Challenges due to floating application of MPD on the Skarv/Idun field

5.3. Preparation and planning

5.3.1. Importance of hole cleaning

5.3.2. Appropriate Equipment Arrangement

5.4. Installation, commissioning, testing and training

5.5. Well control procedures

5.6. Possible problems

**6. Comparison of drilling concepts on the Skarv/Idun field**

6.1. Conventional drilling program

6.2. Managed Pressure Drilling solution

6.3. Drilling-related benefits of using MPD technology on the Skarv field

6.4. Reservoir/Production-Related benefits of using MPD technology on the Skarv/Idun field

6.5. Economic viability of using MPD technology on the Skarv/Idun field

**7. Conclusions**

7.1. Discussion on the Study

7.2. Recommendations

**VIII. Nomenclature**

**IX. References**

# V. List of Tables


**Tab. 1.** Comparison of BHP values for conventional drilling and MPD

**Tab. 2.** Exploration wells in the Skarv field

**Tab. 3.** Exploration wells in the Idun field

**Tab. 4.** Subsea Development plan for wells

**Tab. 5.** Tubing and Flowline sizes and lengths

**Tab. 6.** Fluid contact informations for the Skarv Field

**Tab. 7.** Fluid contact informations for the Idun Field

**Tab. 8.** Overview of the gas PVT parameters (Gas expansion and Condensate-gas Ratios) and oil PVT parameters (Oil shrinkage and Gas-oil Ratios) used for estimation of in-place volumes for the Skarv Field.

**Tab. 9.** Reservoir Conditions and Fluid Properties

**Tab. 10.** GIIP & STOIIP estimates for the Skarv Field. Volumes in field units and include associated gas and condensate oil

**Tab. 11.** GIIP & STOIIP estimates for the Skarv Field. Volumes in field units and include associated gas and condensate oil

**Tab. 12.** Transocean Polar Pioneer – general information/dimensions

**Tab. 13.** Transocean Polar Pioneer – environmental criteria for operation

**Tab. 14.** Transocean Polar Pioneer – storage capacities

**Tab. 15.** Transocean Polar Pioneer – marine equipment

**Tab. 16.** Transocean Polar Pioneer – drilling equipment

# VI. List of Figures

**Fig. 1.** Managed Pressure Drilling (pressure-depth chart)

**Fig. 2.** Non-Productive Time pie chart

**Fig. 3.** MPD benefits

**Fig. 4.** Comparison of conventional drilling and CBHP MPD variation - pressure-depth charts

**Fig. 5.** Comparison of conventional drilling and CBHP MPD variation

**Fig. 6.** HSE MPD - overview

**Fig. 7.** Dual Gradient MPD variation (pressure-depth chart)

**Fig. 8.** Overview of the Pressurized Mud Cap Drilling MPD variation

**Fig. 9.** Pressurized Mud Cap Drilling MPD (pressure-depth chart)

**Fig. 10.** Rigging up Pressurized Mud Cap Drilling MPD variation

**Fig. 11.** Comparison of the Dual Gradient MPD and Conventional Riser Drilling on floaters

**Fig. 12.** Outline of the Reelwell Drilling Method

**Fig. 13.** Overview of the Reelwell Drilling Method from a semi-submersible drilling rig

**Fig. 14.** Equipment requirements to conduct MPD operation

**Fig. 15.** Rotating Control Device

**Fig. 16.** Non-Return Valve

**Fig. 17.** Basic principle of using Downhole Deployment Valves

**Fig. 18.** ECD Reduction Tool

**Fig. 19.** Coriolis Flow Meter

**Fig. 20.** Nitrogen Generation Unit

**Fig. 21.** MPD Multiphase Separation System

**Fig. 22.** U-Tube effect in deepwater drilling

**Fig. 23.** Wellbore ballooning

**Fig. 24.** Location of the Skarv and Idun fields

**Fig. 25.** Skarv/Idun development concept with FPSO and semi-submersible drilling rig

**Fig. 26.** Regional Structural Elements and location of Skarv/Idun fields

**Fig. 27.** Source rock distribution in the Skarv/Idun area

**Fig. 28.** 3D view of the Skarv/Idun field with exploration wells

**Fig. 29.** Overview of the Skarv/Idun development wells

**Fig. 30.** Well Trajectory Overview Skarv A / Tilje

**Fig. 31.** Well Trajectory Overview Skarv B & C

**Fig. 32.** Well trajectory overview for the 2 gas producers on Idun

**Fig. 33.** Pore, fracture, overburden and LOT pressures for the Skarv area

**Fig. 34.** Temperature prognosis for the Skarv/Idun development

**Fig. 35.** Schematic Pipeline Layout used in Simulation Model

**Fig. 36.** Skarv FPSO

**Fig. 37.** Regional Line (3D) and interpretation of structural style across the Nordland Ridge and Donna Terrace

**Fig. 38.** 3D regional surface showing the top Garn depth, location of main structures, wells and regional line depicted in Figure 35.

**Fig. 39.** Skarv/Idun seismic survey area

**Fig. 40.** Skarv appraisal well 6507/5-2 showing interpreted horizons

**Fig. 41.** Stratigraphic column of the Skarv/Idun field

**Fig. 42.** Cross-section of the Skarv and Idun Fields illustrating the position of fluid contacts

**Fig. 43.** Technical production profile for the Skarv/Idun Development

**Fig. 44.** Distribution of Stock Tank Oil Initially in Place (STOIIP) within the Skarv Field (volumes are in MMbbl and include condensate oil)

**Fig. 45.** Distribution of Gas Initialy in Place (GIIP) within the Skarv Field (volumes reported in Bcf and include associated solution gas)

**Fig. 46.** Skarv Idun Reservoir Model Simulation Grid

**Fig. 47.** Idun Simulation Model

**Fig. 48.** Polar Pioneer semi-submersible drilling rig

**Fig. 49.** MPD candidate selection Flow Diagram

**Fig. 50.** MPD candidate selection Flow Diagram for the Skarv/Idun conditions

**Fig. 51.** MPD set up for the Constant Bottom-Hole Pressure variation

**Fig. 52.** Below Slipjoint MPD system dedicated for deepwater applications

**Fig. 53.** The Snadd North prospect showing the location of exploration well 6507/5-6 S and a planned horizontal sidetrack to a producer (perspective view)

**Fig. 54.** The Snadd North prospect showing the location of exploration well 6507/5-6 S and a planned horizontal sidetrack to a producer (top view)

**Fig. 55.** Polar Pioneer – Profile view

**Fig. 56.** Polar Pioneer – Front view

**Fig. 57.** Polar Pioneer – Top view

**Fig. 58.** Polar Pioneer – Main deck

**Fig. 59.** Polar Pioneer – Drillfloor

# VII. Objective

- Evaluate both technical and economical feasibility of using Managed Pressure Drilling technology from the Transocean's Polar Pioneer semi-submersible drilling rig on the Skarv/Idun field on the Norwegian Continental Shelf;
- Show reservoir and drilling benefits of using Managed Pressure Drilling compared to the conventional drilling;
- Assess which Managed Pressure Drilling variant is most suitable for the Skarv/Idun reservoir conditions;
- Show which additional equipment is necessary to conduct MPD operation from the Polar Pioneer semi-submersible drilling rig and what rig modifications are needed;
- Show necessary procedures, which have to be done before rigging up this technology on a Transocean's Polar Pioneer;

# 1. Introduction

Managed Pressure Drilling (MPD) is an advanced form of a primary well control mainly deploying a closed and pressurizable drilling fluids system which allows more precise control of the pressure profiles throughout the wellbore than adjustments of mud weight and mud pump alone. Managed Pressure Drilling is a relatively young technology (first time has been introduced to the industry at the IADC/SPE Amsterdam Drilling Conference in 2004), that has improved some old ideas like Underbalanced Drilling (UBD) and Power Drilling.

The International Association of Drilling Contractors (IADC) defines it as "an **adaptive drilling process** used to more **precisely control the annular pressure** profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly". In other words the main aim of MPD is to avoid continuous influx of formation fluids to the surface by maintaining a state of effective overbalance. It's done by applying surface back - pressure during drilling ahead or shut-in to make a connection of jointed pipe.

Further after the IADC and MPD Forum definitions:

- MPD processes employ a collection of tools and techniques which may mitigate the risks and costs associated with drilling wells that have narrow downhole environment limits, by proactively managing the annular hydraulic pressure profile.
- MPD may include control of backpressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations thereof.
- MPD may allow faster corrective action to deal with observed pressure variations. The ability to dynamically control annular pressures facilitates drilling of what might otherwise be economically unattainable prospects.
- MPD techniques may be used to avoid formation influx. Any flow incidental to the operation will be safely contained using an appropriate process.

## 1.1. Basic principles of Managed Pressure Drilling

Drilling related issues like narrow pore to fracture "pressure windows" and related to this kick/loss and well control scenarios, loss of circulation and associated excessive mud costs, differentially stucked pipe, excessive casing program, slow Rate of Penetration (ROP) and well control issues contribute to defining the necessity for a more effective drilling technology. High amount of Non-Productive Time (NPT) in offshore drilling results in high drilling costs and therefore cause the necessity for more precisely control wellbore pressures. Managed Pressure Drilling come across those needs and could significantly reduce the amount of NPT. Most of the Managed Pressure Drilling variants rely on the ability to apply desired value of surface back – pressure to the mud return system and therefore maintaining the Bottom-Hole Pressure between even very narrow pressure windows, reduced possibility of well control situating improving HSE issues.

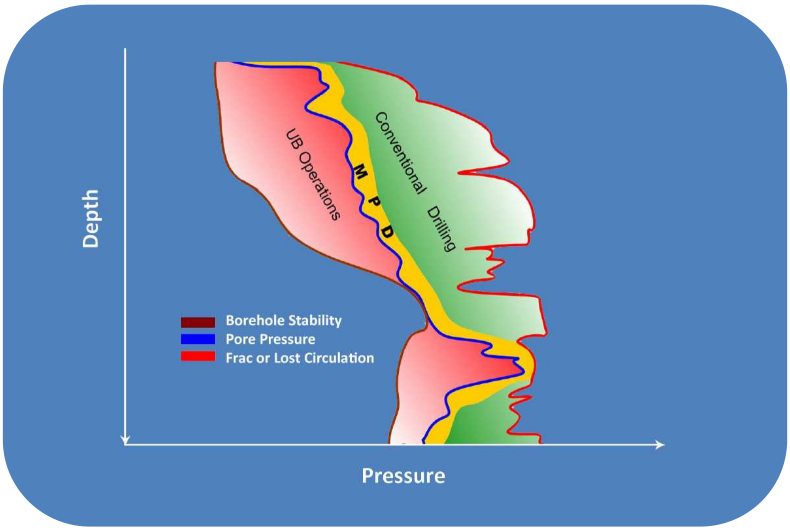


Fig. 1 Managed Pressure Drilling (pressure-depth chart).

In conventional drilling Bottom-Hole Pressure is equal to the sum of hydrostatic mud weight and the circulating friction pressure. Circulation friction pressure is known also as an equivalent circulating density (ECD). This variable exists when the drilling is ahead and pumps are on, when pumps are off (ex. during making the connection) this variable is equal to zero. If drilling with narrow pressure windows, kick/loss scenarios may often occur. For example after shut in for making a connection, when the BHA is at a depth where Bottom-Hole Pressure is near to the frac gradient, when the pumps are started again circulating friction pressure increases to retrieve the circulation, it may results in exceeding fracture gradient and cause loss in circulation, differential stucked pipe etc. Whether the MPD with its closed and pressurizable system is applied, another important variable has to be added to that equation to determine the value of Bottom-Hole Pressure. This variable is the ability to add the backpressure. If essentially incompressible fluid is considered, each surface pressure adjustments result in immediately changing BHP.

| Conventional Drilling | Managed Pressure Drilling |
|---|---|
| $BHP = MW + ECD$ | $BHP = MW + ECD + BP$ |

Tab. 1 Comparison of BHP values for conventional drilling and MPD

## 1.2. Advantages and Methods of Managed Pressure Drilling

Currently at least half of all offshore prospects are economically undrillable with conventional drilling methods using conventional drilling equipment. Main reasons of "economically un-drillable prospects" are excessive costs caused by drilling-related issues or barriers. Drilling-related situations such as loss of circulation, occurrences of differentially stucked pipe, twisting off, kick/loss scenarios contribute significantly to a growing number of prospects that exceeds the Authorization For Expenditure for the drilling program.

MPD can reduce the possibility that those problems occurs and therefore **allows drilling through the un-drillable in conventional way formations**, helps to **reduce Non-Productive Time** (as it is highlighted in the Fig. 2 Non-Productive Time can be reduced by almost a half by introducing the Managed Pressure Drilling) and to **overcome** several **drilling problems** such as:

- drilling with narrow “pressure window”, where is a small difference between the pore and fracture pressure (MPD allows to drill deeper open hole sections where the frac-pore pressure windows are tight);
- Avoid kick-loss and well control scenarios caused by the narrow margins;
- Excessive casing programs (MPD helps to reduce number of casings);
- Helps to improve Rate of Penetration (ROP) and reduces non productive time;
- Excessive drilling fluids costs caused by the loss of circulation;
- Failure to reach Target Depth with large enough hole diameter;
- Shallow geohazards, both with drilling riserless and with casing or marine riser;

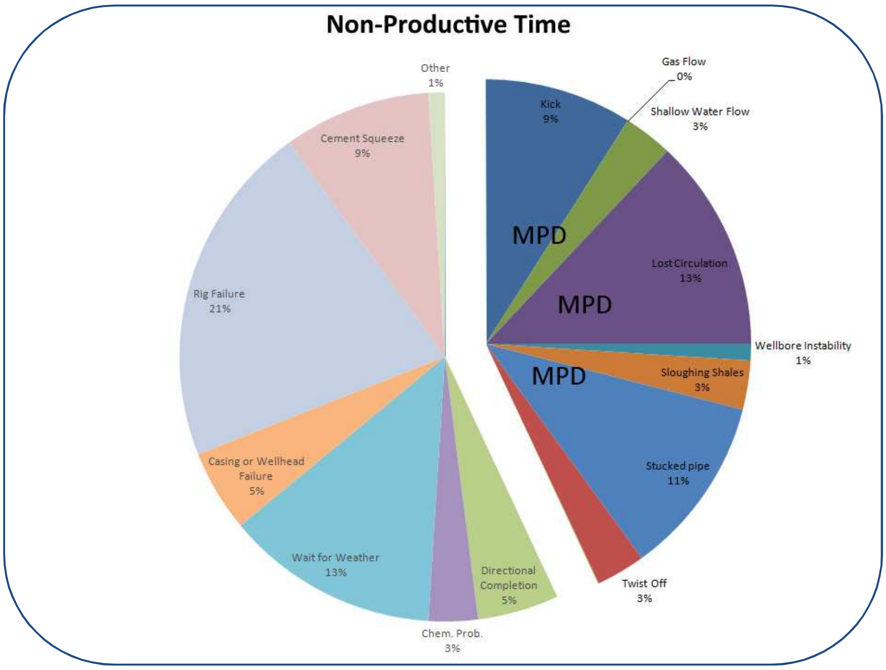


**Fig. 3 Non-Productive Time (NPT) pie chart (Source: SPE 112803; Ref. no 29.)**

## Benefits of using MPD

### Improved drilling efficiency by:

- Early influx/losses detection;
- Accurately managed mud program;
  - increased ROP;
  - reduced mud weight;
  - reduced ECD/BHP;
  - reduced formation damage;
  - reduced possibilities for differential stuck pipe;
- Early identification of wellbore ballooning;

### Reduced costs by:

- Decreasing Non-Productive Time(NPT) associated with:
  - dealing with losses;
  - controlling kicks and circulation issues;
  - incidents of differentialy stucked pipe;
  - fishing events;
  - time spent on flow checks to find out the difference between wellbore ballooning and formation influx;
- Improved drilling efficiency;
- Optimum management of the mud program;
- Reduced number of casing strings;

**Fig. 2 MPD benefits**

## 1.3. Managed Pressure Drilling variations

Before discussing the MPD variations, it should be mentioned, that Managed Pressure Drilling is divided into two categories: a "**reactive**" – when well is planned to drill with conventional wisdom casing set points and rig is equipped with at least Rotating Control Device, choke and drillstring non-return valves to acts better if it will be a well control situation; and a "**proactive**" – when well is planned from the beginning to be drilled using MPD, and drilling programs takes full advantages of the ability to use this technology by precisely managed pressure profiles through the wellbore. This category is very beneficial in offshore drilling due to more costly Non-Productive Time and typically more challenging well hydraulics than onshore.

Currently there are several variations of MPD in use:

- **Constant Bottom-Hole Pressure MPD**: the objective is to drill with a fluid that is lighter than conventional wisdom would prescribe, so that bottom-hole pressure is maintained constant, whether the fluid column is static or circulating. The loss of annulus flowing pressure when not circulating is counteracted by applied surface backpressure;
- **HSE MPD (called also Returns Flow Control)**: the objective is to drill with closed annulus return system vs. an open to atmosphere drilling or bell nipple to enhance health, safety and environment issues;
- **Deepwater Dual Gradient MPD**: an inert gas or liquid fluid is injected at some predetermined depth into the casing or marine riser. It results with different pressure-depth gradient above the injection point and different below - thus the term dual-gradient. This technique is helpful as a means of adjusting the effective bottom-hole pressure without having to change base fluid density and with fewer interruptions to drilling ahead, usually to avoid lost of circulation in a theft zone or to minimize differential sticking of the drill string. The intention of using this method is to avoid gross overbalance not to exceed the fracture gradient;
- **Pressurized Mud Cap MPD**: the objective is to deal with severe loss circulation issues. When severe loss begins to occur, then heavy mud is pumped through the Rotating Head in the annulus on a predetermined column height. This is called a mud cap and it acts as an annulus barrier. During this operation light and not damaging fluid (very often

seawater) is used to drill into the zone with depleted pressure. Application of required amount of back pressure prevents annulus returns to the surface and furthermore reduces drilled cuttings gas migration. Due to using light fluid ROP increases and cheap drilling fluid and cuttings are forced into the troublesome formation that would otherwise results with loss circulation;

- **Reelwell Drilling Method (RDM)**: use a Dual Drill String where the drill string annulus carries the drilling fluid to the bit, and the return flow to surface is through a concentric inner string. RDM requires several dedicated equipment to conduct this operation like a Top Drive Adapter (dual conduit swivel that allows rotation of the drill string with the top drive), the Dual Float Valve (enables downhole pressure isolation of the well and facilitates controlled pressure drilling and pressure less pipe connections), a Piston (prevents loss of annular well fluid to under pressured zones), a Flow Control Unit (control valve arrangement where all the active drilling fluid is routed through) and an Upper Annular Control Unit (pump unit where the main function is to top-up and keep constant pressure in the annulus behind the piston). RDM has several benefits over a traditional drilling like improved hole cleaning by removing cuttings just behind the bit, reduce of formation damage by avoid loss of annular fluid and low costs of drilling fluids;
- **Riserless MPD**: a subsea rotating device and ROV is used when establish a subsea location via riserless drilling with seawater. ROV adjusts subsea backpressure at the mud-line. Closing the subsea choke increases bottom-hole pressure. This technique is useful to control shallow geo-hazards (shallow gas or abnormally pressure aquifers);
- **Zero Discharge Riserless MPD** (called also dual gradient riserless drilling): this variation of MPD incorporates the use of a subsea RCD, subsea pump and a returns line back to the rig. The rig's mud pumps plus drilling fluid density and cuttings create one pressure-depth gradient from the mud line down. The regulating rate of the subsea pump contributes to another pressure-depth gradient with mud and cuttings from the mud line to the rig. Bottom-hole pressure can be adjusted by backpressure, subsea and rig pump rates combination of those;

### 1.3.1. Constant Bottom-Hole Pressure

The objective is to drill with a slightly lighter than conventional wisdom fluids program, nearer balanced. When shut-in to make jointed pipe connections, surface backpressure maintains a desired degree of BHP overbalance, controlling influx. Constant Bottom-Hole Pressure MPD variation reduces non-productive-time (NPT) and enables fewer and deeper casing strings when pressure windows are narrow.

In Constant Bottom-Hole Pressure MPD variation the annular pressure in a well is remains constant at the predetermined depth whether the mud pumps are on or off. The loss in annulus flowing pressure when the pumps are off is counteracted by applying surface backpressure. A Rotating Control Device (RCD) and rigged up above the BOP and an additional choke facilitate control. In effect, the change in BHP resulting from equivalent circulating density during conventional drilling is moved to surface. In other words the mud density is lowered and the lost in density is replaced by the surface backpressure. During making connections when the mud pumps are stopped, the choke is closed to apply necessary annulus backpressure at the surface.

A constant Bottom-Hole Pressure is maintained at the BHA. The result of this is that, as the hole is being drilled ahead or circulated clean, bottom-hole pressure doesn’t change from a static value. Therefore drilling can be carried out with less than conventional ECD, there is less chance to exceed the fracture-pressure gradient, and losses are not incurred, the hole section can be drilled deeper, but formation fluid influx is not invited either, as planned static bottom-hole pressure is above the formation pressure. The well is not in the state of underbalance at any time. This MPD variation allows also setting deeper casing shoes and can sometimes reduce total number of casing strings required to reach target depth. This helps to reach the target depth with hole large enough and that’s why it improves productivity issues.

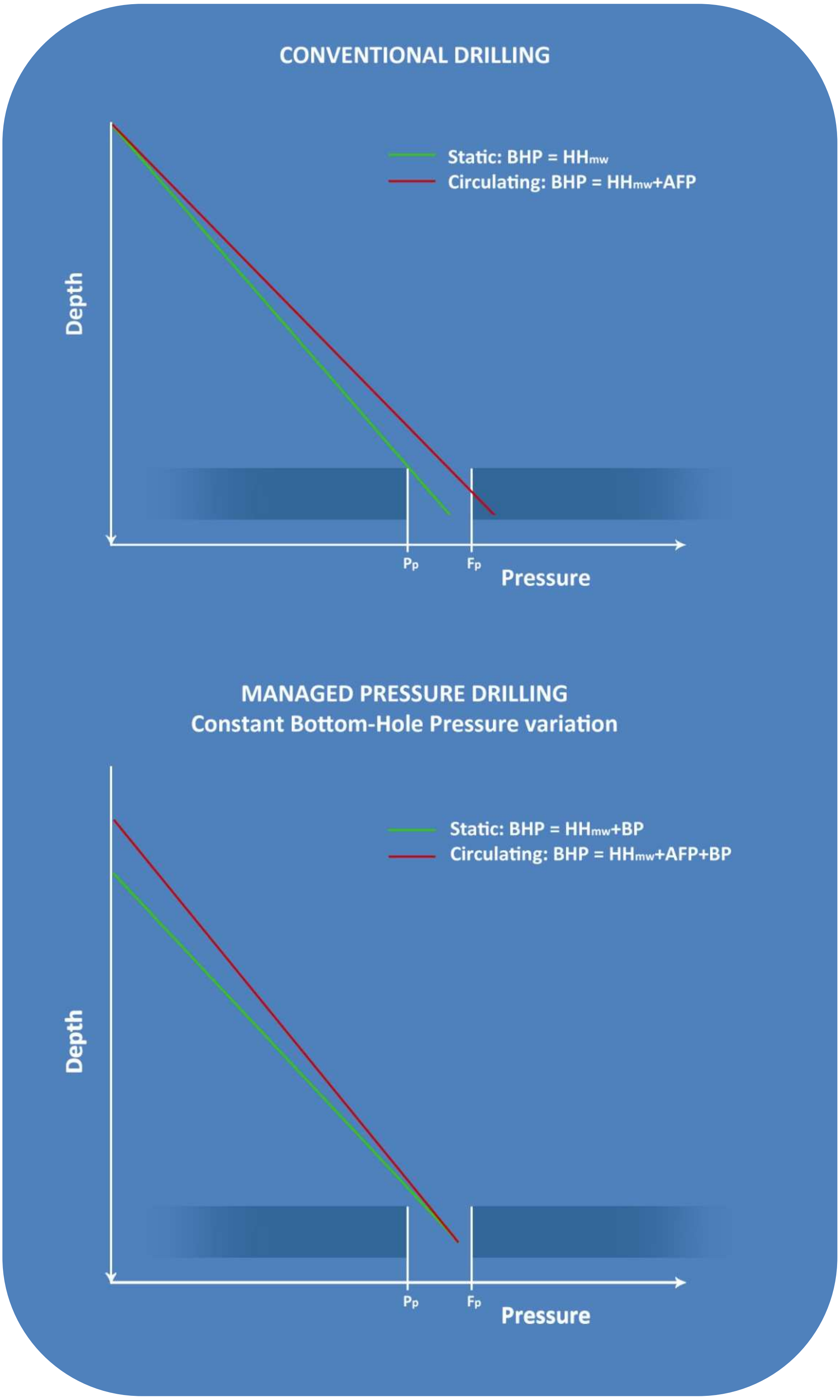


**Fig. 4 Comparison of conventional drilling and CBHP MPD variation - pressure-depth charts**

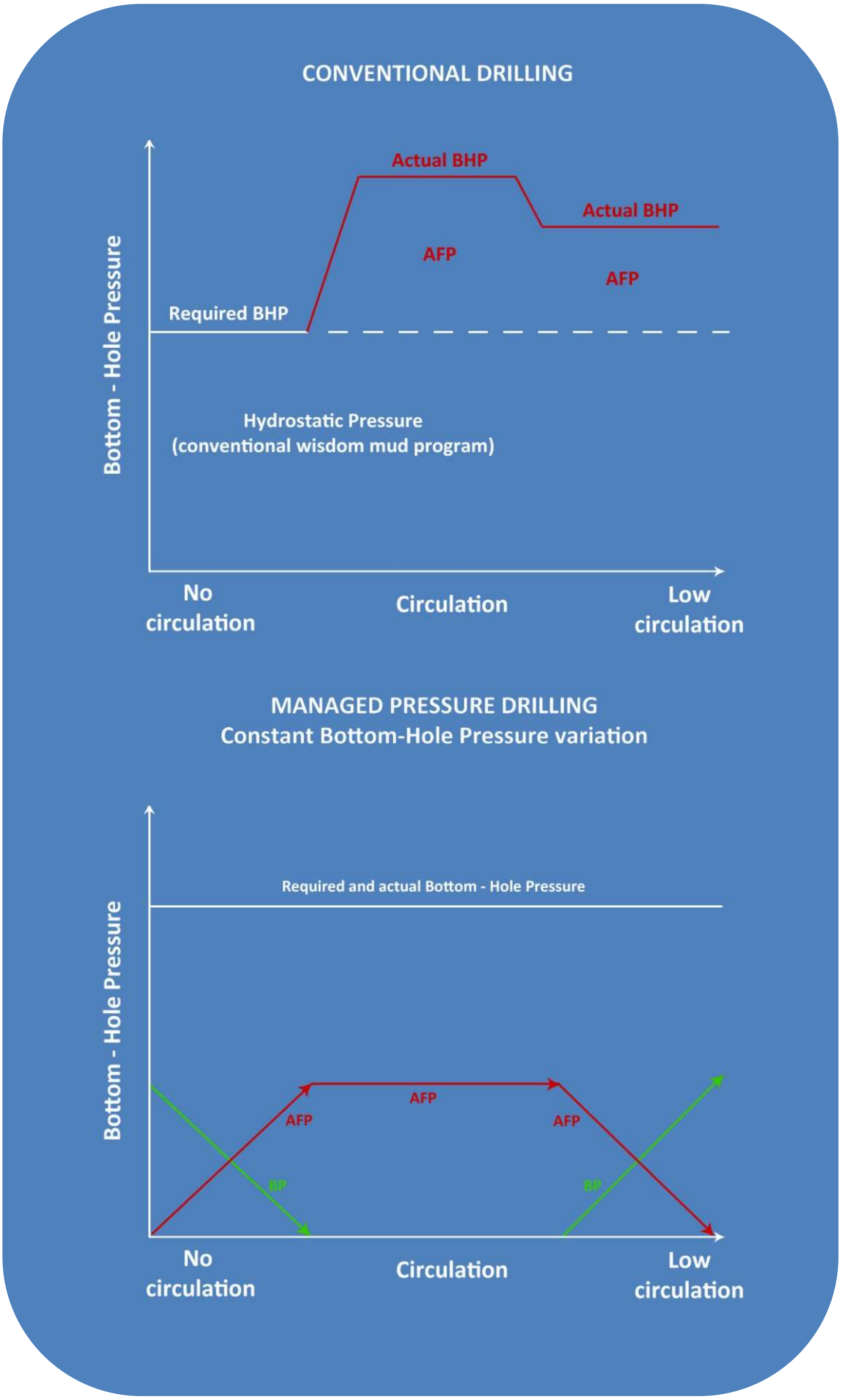


**Fig. 5 Comparison of conventional drilling and CBHP MPD variation**

## 1.3.2. HSE MPD

In the HSE variation of MPD (sometimes called Returns Flow Control), the main objective is to gain benefits from the closed to the atmosphere mud return system, which improves therefore health, safety and environmental issues especially for the rig crew working on the rig floor. By the closed mud returns system and using the Rotating Control Device (which is positioned above the Blow-Out Preventer) any gas, including $H_2S$ is prevented from the spilling onto the rig floor. It is used as a safety measure. If any kick occurs during the drilling or trip in/out and gas spills onto rig floor, then the flowline to the mud shakers is closed and the flow is directed to the choke manifold, where kick is controlled and circulated out of the hole.

This variation of MPD is sometimes used, when drilling from a production platform and hydrocarbon production is ongoing. The objective there is to prevent the gas, which is transported up the hole with the drilling cuttings from escaping to the atmosphere at the bell nipple, drilling nipple or upper marine riser and therefore causing dangerous situation for the personnel working on the rig floor.

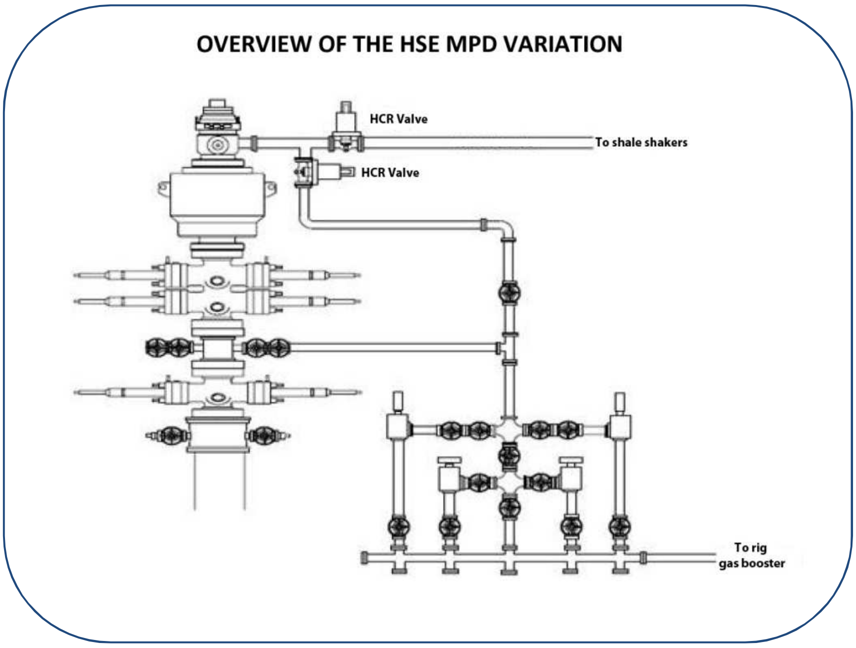


Fig. 6 HSE MPD – overview (Source: SPE 119875; Ref. no 35.)

In other words HSE variation minimize the risk of well control situations, when drilling in hazardous fluids or into the zone with high concentration of toxic gases, worsens by the narrow pore-frac "pressure windows".

## 1.3.3. Deepwater Dual-gradient MPD

An air, inert gas (such as nitrogen) or light liquid is injected at the predetermined depth into the marine riser, to adjust value of the Bottom-Hole Pressure without changing the mud density. The main objective is to avoid the gross overbalance and not exceed the fracture gradient especially in shallow formations, which is caused in deepwater by pumping heavy drilling fluid through the long distance between the sea surface and seabed. Dual Gradient allows the operator to manipulate the pressure profile to fit between pore and fracture pressure. This technique may be also accomplished in offshore environments via the concentric string, or in case of floaters with booster pumps, through the booster pump line. In case of using booster pump and booster pump line a small diameter return line is run from the seabed to circulate the drilling fluid and mud cuttings. Marine riser is filled with the seawater. A booster pump is used to lift the mud cuttings and the drill fluid from the wellbore annulus up to the rig floor. By using seawater in the marine riser, a more dense mud is used in the wellbore to achieve the required value of the BHP. The result of that operation is one pressure-depth gradient above the injection point and another below. That's why the term dual gradient.

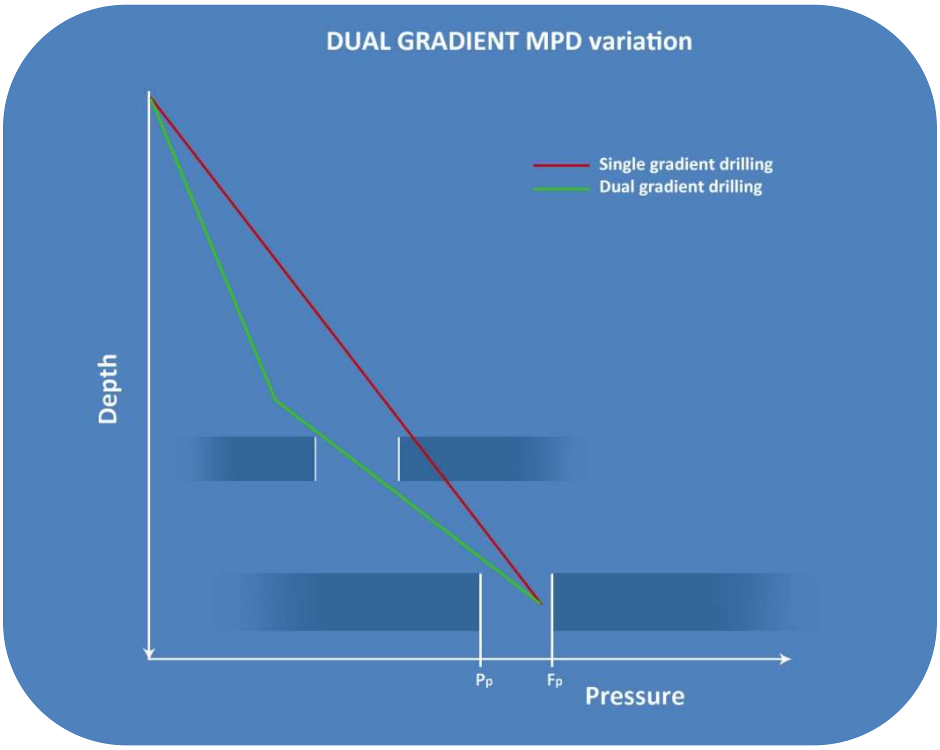


Fig. 7 Dual Gradient MPD variation (pressure-depth chart)

### 1.3.4. Pressurized Mud Cap Drilling

Pressurized Mud Cap Drilling is the drilling with no returns to the surface. The main concept behind this is to pump a predetermined column height of heavy mud (ex. kill fluid) down the annulus through the rotating head. This "mud cap" serves as an annular barrier. Then typically a lighter and non-damaging fluid (ex. seawater) is used to drill into the depleted pressure zone (Fig. 8). Mud with drilled cuttings is simply injected into the troublesome (highly fractured, probably with voids and caverns) zone. It results with higher ROP (because of the drilling with lighter mud). Mud sacrificed into the depleted zone is less expensive than conventional. Therefore well control is enhanced compared to drilling conventional way with huge, sometimes almost total mud losses and productivity is enhanced by drilling with less invasive drilling fluid. PMCD technique is used mostly when dealing with reservoirs that could result in a severe loss (ex. depleted reservoirs) of circulation with the main objective to minimize the mud losses and Non-Productive Time, when drilling in highly depleted zones or formations with large voids, like caverns.

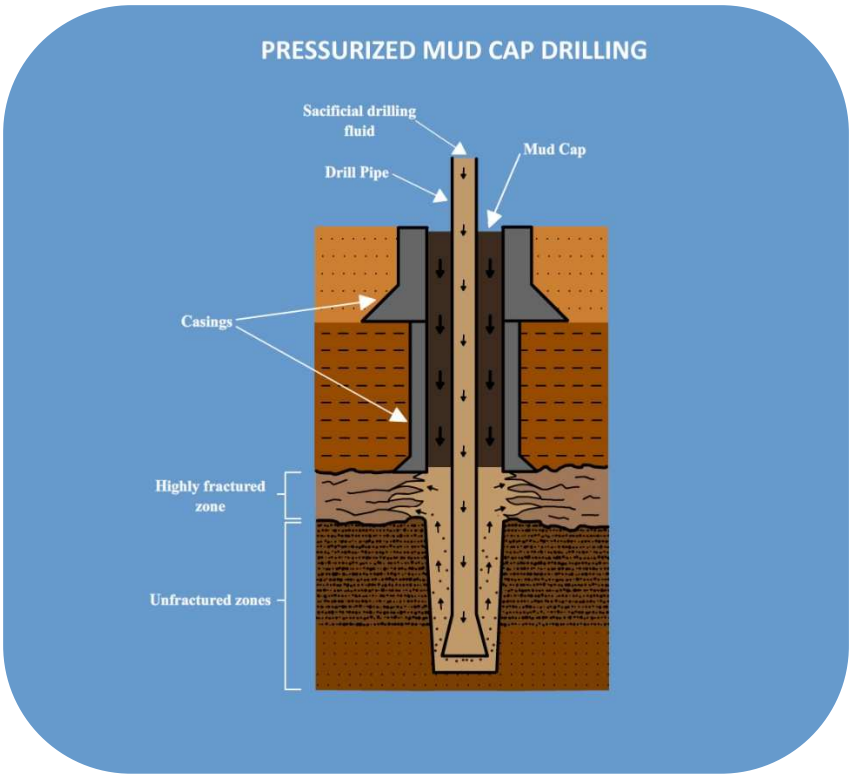


Fig. 8 Overview of the Pressurized Mud Cap Drilling MPD variation

The PMCD method also by using heavy “mud cap” in the annulus keeps the well under control and prevents any gas influx from reaching the rig floor.

The important aspects of Pressurized Mud Cap Drilling method are the Rotating Control Device, “mud cap”, and used drilling fluid. Rotating Control Device allows the operator to pump the “mud cap” into the annulus and also to keep pressure at the surface to compensate the lower mud weight of the drilling fluid used to control the reservoir pressure during drilling. A flow spool has to be installed below the Rotating Control Device to allow fluid to be pumped into the annulus. The manifold connected to the RCD is the bleed off manifold – is used to be able to keep the well full from the trip tank. It also allows any pressure to bled off from the stack should this be required when changing Rotating Control Device packers. “Mud cap” should be of course suited to the specific job. Rigging up Pressurized Mud Cap Drilling configuration is shown in the Fig. 10.

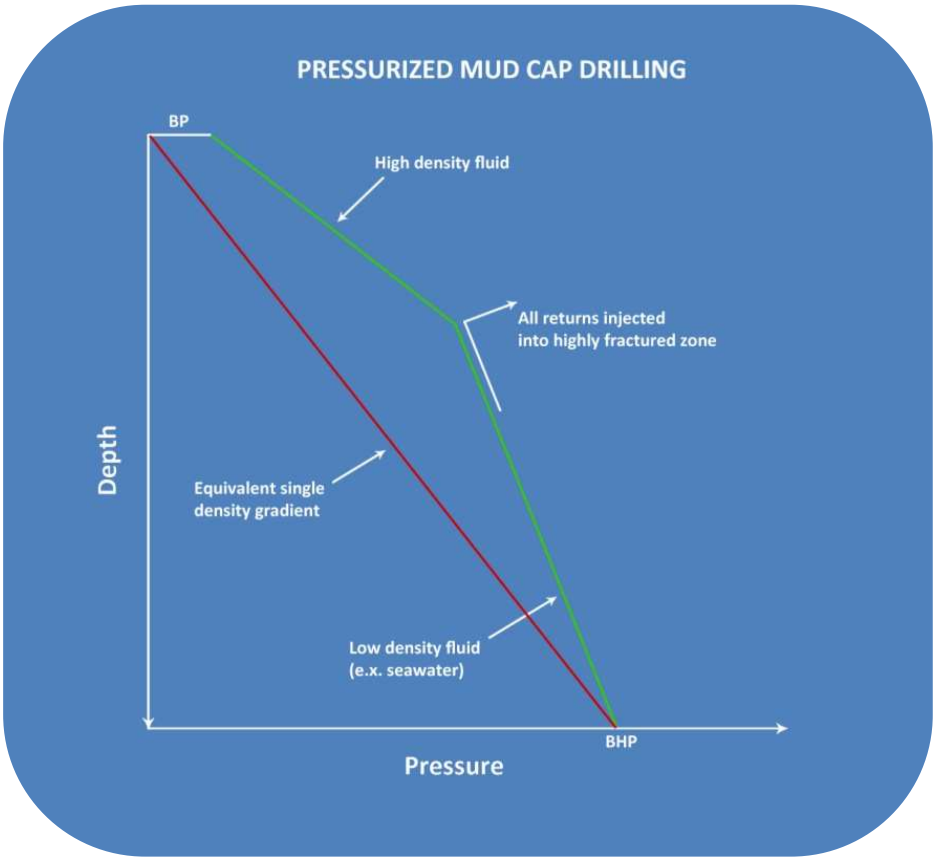


Fig. 9 Pressurized Mud Cap Drilling MPD (pressure-depth chart)

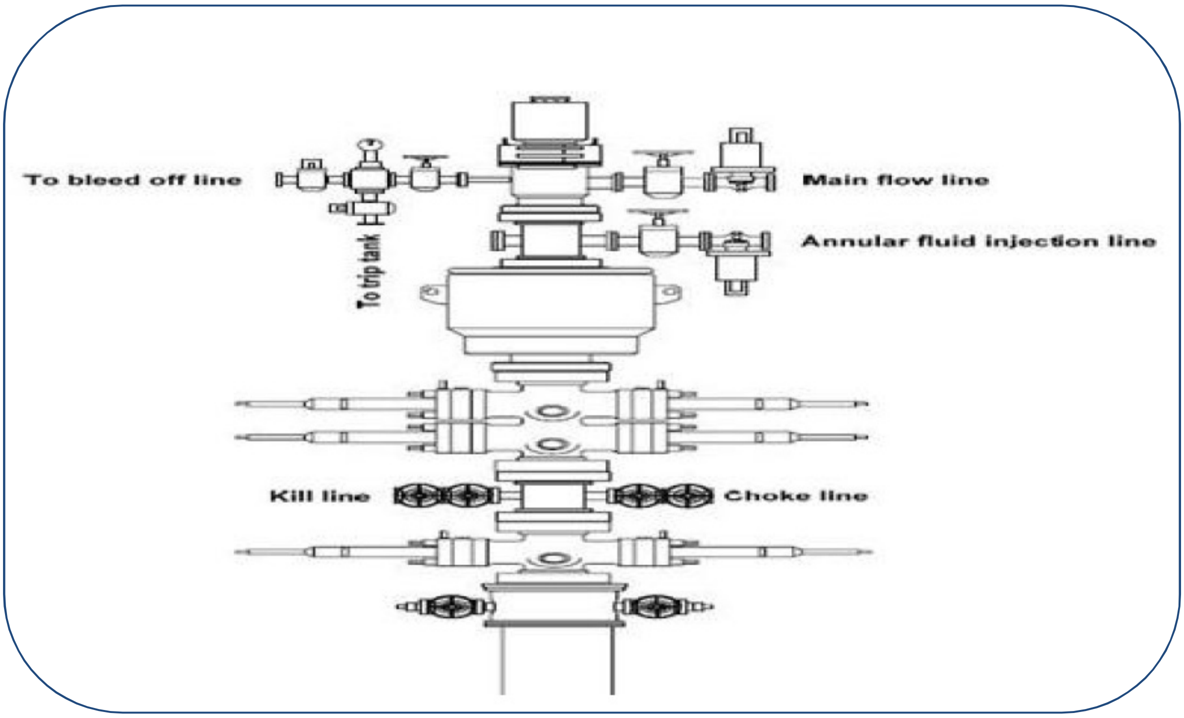


Fig. 10 Rigging up Pressurized Mud Cap Drilling MPD variation
(Source: SPE 119875; Ref. no 35.)

## 1.3.5. Riserless MPD

Riserless MPD is occasionally used when drilling in deepwater from floating platforms. This method can be shortly described as a riserless pumping and dumping with subsea well control. A subsea ROV is used when establishing a subsea location via riserless drilling with seawater (it can be other fluid adaptable to be discharged onto the seabed). The ROV or the subsea automatic choke can be used to adjust subsea backpressure at the flow line outlet the Rotating Control Device. Closing the subsea choke increases Bottom-Hole Pressure, virtually as if the subsea location was being drilled with a marine riser filled with mud and cuttings. It results with a degree of overbalance greater than the drilling fluid itself would impart, useful to control shallow geohazards such as shallow water flow.

## 1.3.6. Zero Discharge Riserless (Dual Gradient Riserless) MPD

This method is sometimes called also Dual Gradient Riserless Drilling. A subsea pump is used in conjunction with a subsea Rotating control Device. It results with the returns of a mud and cuttings to the rig for a proper disposal. Bottom-Hole Pressure can be adjusted through back-pressure, rig and subsea pump rates or the combination of those. Annular frictional pressure losses in this system are smaller than losses in drilling with marine riser. The objective of the system is accurate control of Bottom-Hole Pressure by using the subsea pump. With a subsea pump, Equivalent Circulating Density or Annular Friction Losses is reduced. As it is shown in the Fig. 11 different pressure-depth gradient is above the subsea pump and different below. This method can also significantly reduce the number of casing strings and allows reaching the target depth with large enough hole.

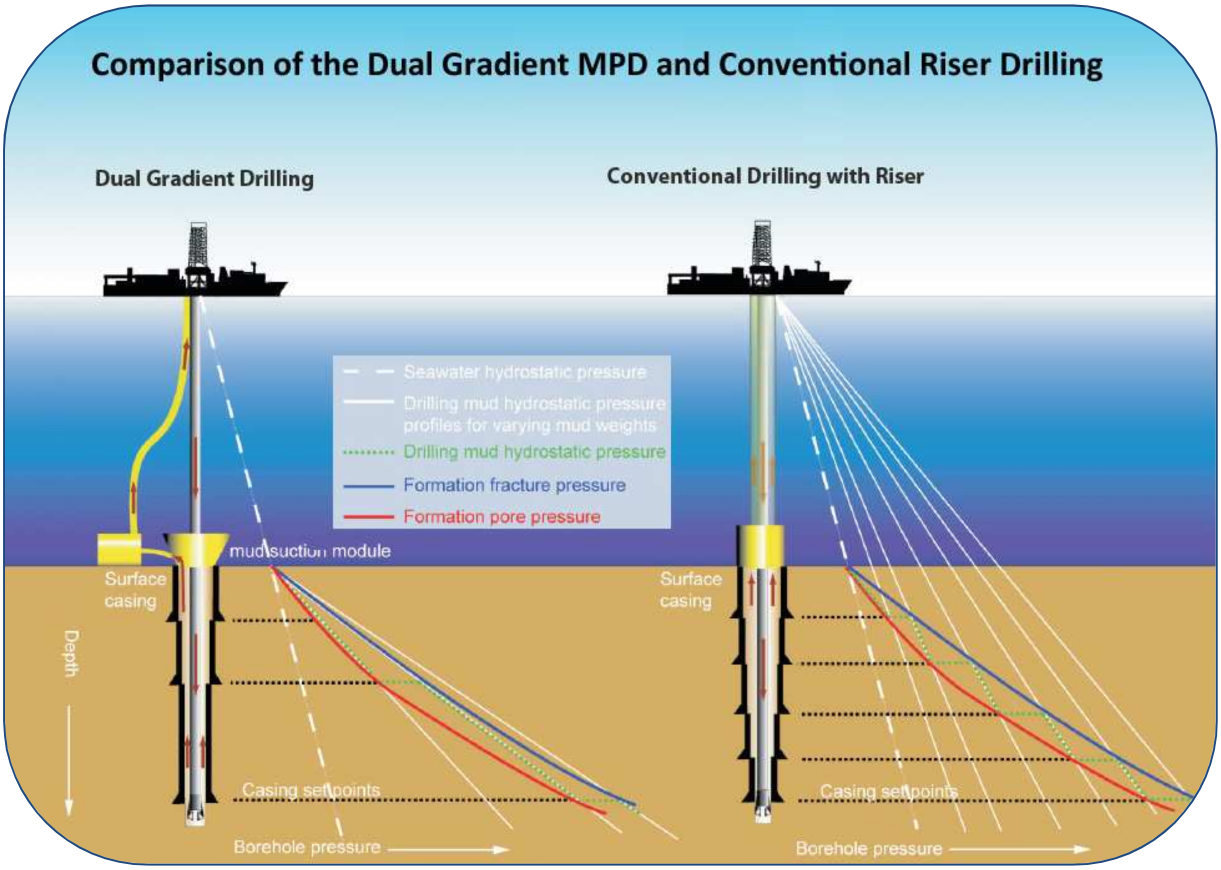


Fig. 11 Comparison of the Dual Gradient Riserless MPD and Conventional Riser Drilling on floaters (Ref. no 34.)

## 1.3.7. Reelwell Drilling Method

Reelwell Drilling Method (RDM) can be defined as another variation of Managed Pressure Drilling. RDM is a riserless drilling method based on applying a concentric drill pipe. It consists of outer pipe joints (5'' or 6 5/8'') and the inner string (specially designed for RDM). Drilling Mud is circulated in a different way compared to conventional drilling - RDM employs a closed-loop circulation system. Drill string annulus (between the outer and inner pipe) carries drilling fluid down to the drill-bit, return flow is through the inner string. Pressure and mud flow is controlled from the surface by the computer system.

There is a need to make modifications to the equipment on the floating platforms to conduct RDM operation (System overview shown in the Fig. 12). Besides use of Dual Drill String, RDM system consists of:

-Top Drive Adapter, which swivel for drill fluid in and out;

-Dual Float Valve, which enables downhole isolation;

-Piston, which pushing the bit forward and isolate wellbore fluids;

-Annulus Control Unit, which controls pressure in the annulus;

-Rotating Control Device (another key tool for RDM), which is used to seal against the drill string to hold pressure in the annulus of drill string/wellbore. In case of floating applications it can be installed on the Top of Low Marine Riser Package (LMRP), on the top of BOP or can be inserted into the BOP;

As it is shown in the Fig. 12 and Fig. 13 main idea behind this system is to ensure the better pressure control (small active fluid system volume reduces Equivalent Circulating Density value and fluid loss) and better hole cleaning by removing the drilling mud with cuttings from the annulus and leaving therefore hole above the piston clean. Reelwell Drilling Method by providing a closed circulation system may be able to overcome many downhole pressure related challenges like a narrow pressure windows, which is common problem in deepwater drilling. By eliminating necessity having a 21'' riser with all its accessories (ex. riser tensioning system) it can be possible to drill in ultra deepwater areas utilizing smaller ($3^{rd}$ or $4^{th}$ generation) floating rigs than in conventional deepwater drilling ($5^{th}$ or $6^{th}$ generation). It is because there is no need to accommodate the riser and apply enough tension on it. Therefore overall cost of drilling is significantly reduced.

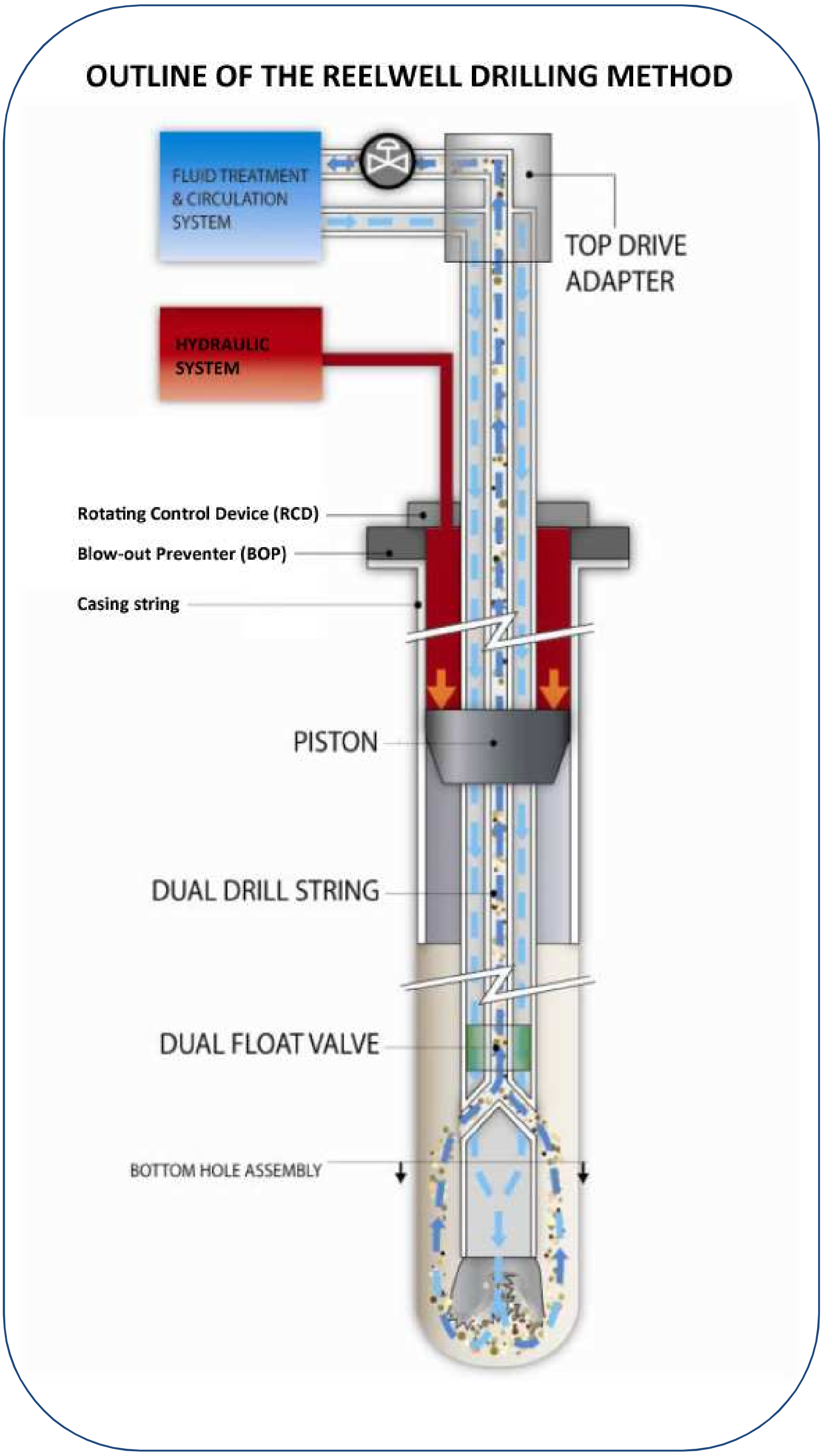


**Fig. 12 Outline of the Reelwell Drilling Method**
**(Source: SPE 126148; Ref. no 16)**

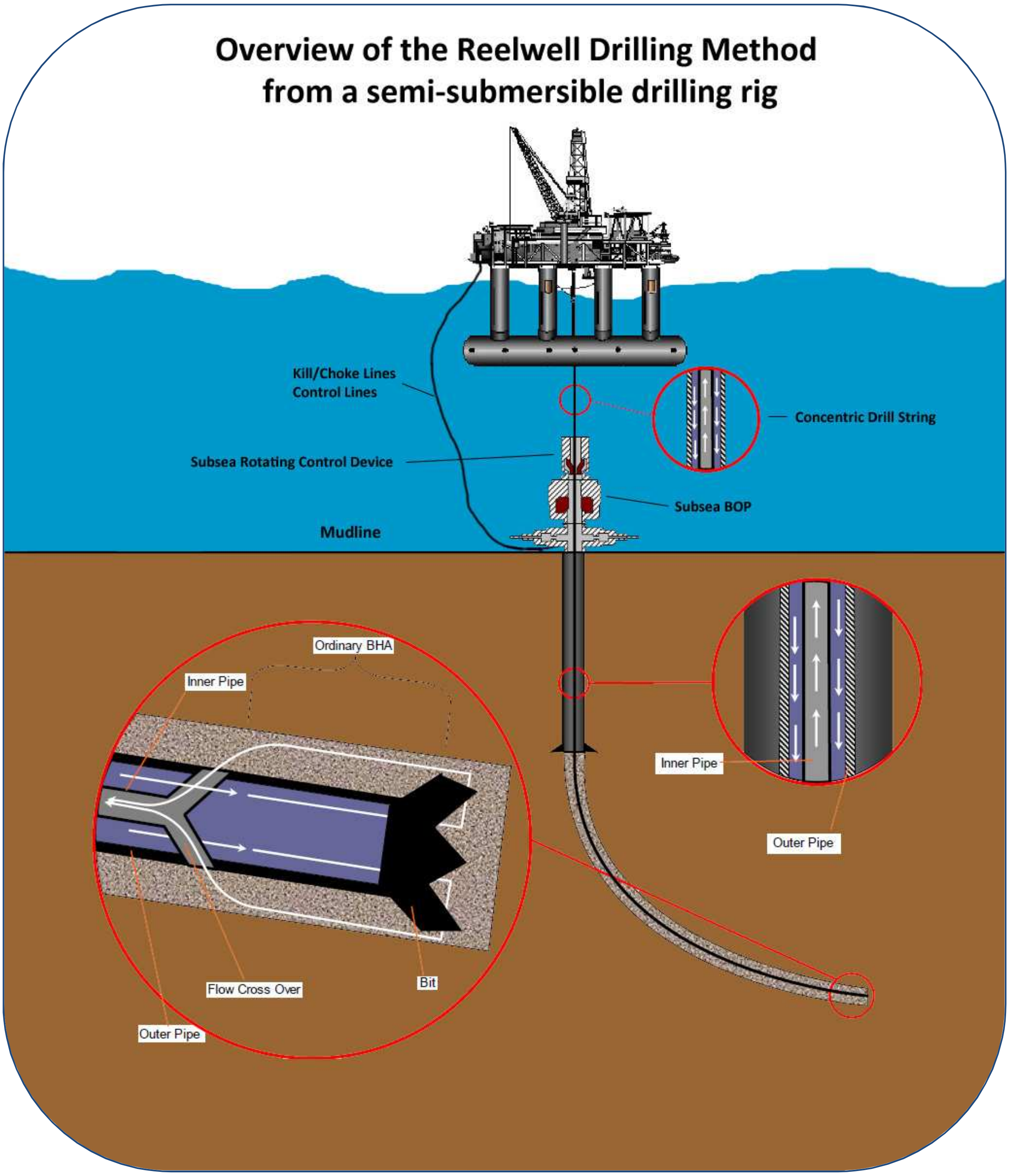


Fig. 13 Overview of the Reelwell Drilling Method from a semi-submersible drilling rig (Source: SPE 126148; Ref. no 16.)

## 1.4. Managed Pressure Drilling – basic tools

Managed Pressure Drilling is called a tooled up technology. It means that to conduct MPD operations there is a need to have some improvements to the equipment (root technology of MPD is UBD practices and equipment). Most of the Managed Pressure variations requires at least a Rotating Control Device (or Rotating Annular Preventer) suitable for the type of rig, a Dedicated Choke Manifold, a Backpressure Pump, Two drillstring non return valves (favorably wire-line retrievable to eliminate possibility of unexpected trip only to replace plugged valve) and dedicated Flow and Return Lines.

According to the Don Hannegan[29] essential tools for MPD operations are:

- Rotating Control Device (floating rigs applications);
  - External Riser Rotating Control Device;
  - Internal Riser Rotating Control Device;
  - Subsea Rotating Control Device
- Rotating Control Device (fixed rigs applications);
  - Passive and Active annular seal design models;
  - Marine Diverter Converter Rotating Control Device;
  - Bell Nipple Insert Rotating Control Device;
  - Internal Riser Rotating Control Head (IRRCH);
- Non-Return Valves;
- Choke Manifolds
  - Manual Manifold;
  - Semi Automatic Manifold;
  - PC Controlled Automatic Manifold;

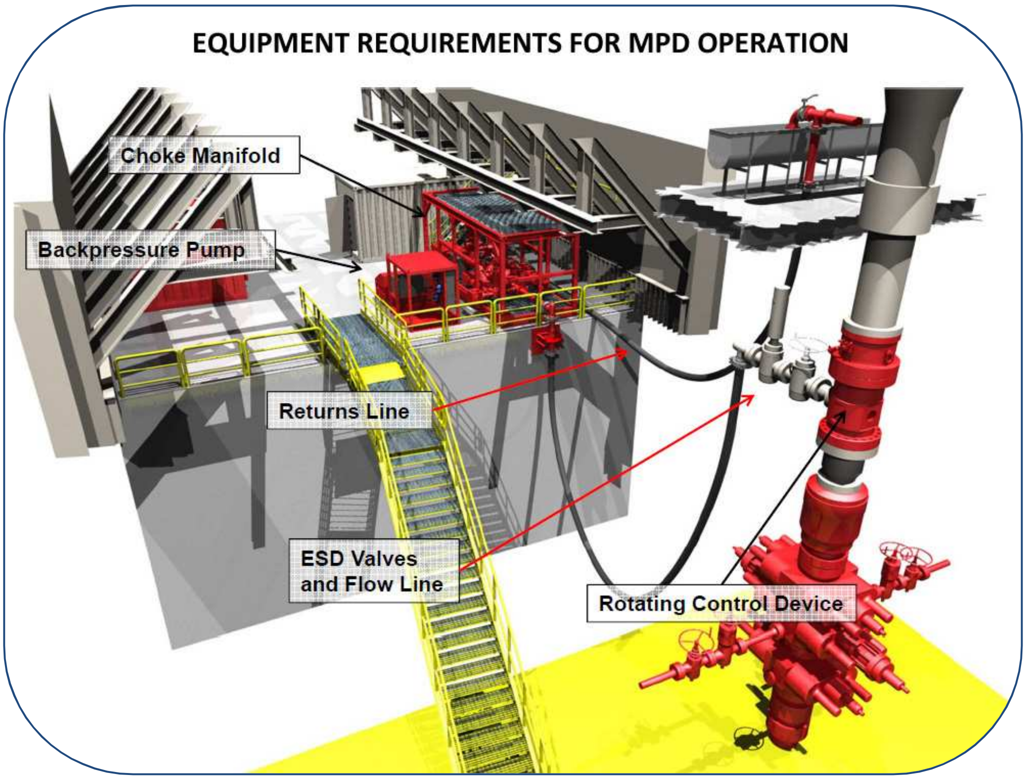


Fig. 14 Equipment requirements to conduct MPD operation (Ref. No 34.)

### 1.4.1. Rotating Control Devices and Rotating Annular Preventers

Rotating Control Devices (RCD) are key enablers of Managed Pressure Drilling. In general, RCD is used in mud-return system to contain the annular fluids during drilling. The primary purpose of using RCD is to divert the upstream flow from the wellbore to the choke manifold, while still maintaining effective seal between the annulus and atmosphere during MPD operations. The technology is based on applying advanced compound sealing rubber against the drillstring (or kelly surface), which provides a required seal and allows vertical movement of the pipe at the same time. Sealing sleeve is placed within a secondary housing, which makes it possible to rotate the drill-pipe, while maintain the necessary seal in the annulus.

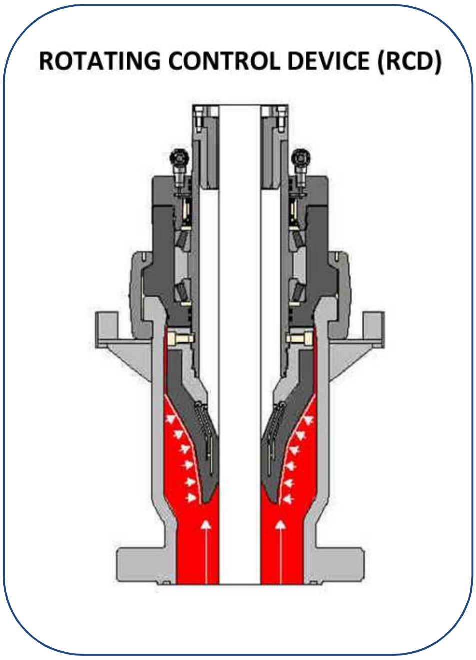


Fig. 15 Rotating Control Device (Ref. No 34.)

Rubber element is mounted on a bearing with the aim to reduce a wear. There are two types of sealing systems:

- Passive System, which use well pressure to assist in sealing (Rotating Control Devices);
- Active System, which use external hydraulic pressure to assist in sealing (Rotating Annular Preventers);

By using these tools it is possible to drill underbalanced, near-balances or overbalanced when facing an elevated risk of gas kicks and to conduct MPD operations.

## 1.4.2. Chokes

Chokes are the other essential tools in each MPD operations used to reduce pressure by increasing frictional pressure loss on the very short distance. It is done by reduce inflow area, which causes increase in fluid velocity. It creates the variable flow restriction that controls the wellhead pressure (WHP) and maintains relatively constant bottom-hole pressure (BHP) both in static and dynamic conditions. MPD chokes as opposed to conventional drilling chokes aren't used as secondary well control equipment.

It should to be taken into consideration that the purpose of MPD is to avoid continuous influx of formation fluids up to the surface and each incidental influx during the MPD operation will be safely contained using a proper procedure. It means that MPD choke is used for pressure control rather than flow control. Choke manifold has to have the same pressure ratings as preventer stack. MPD choke manifold is often connected to the Rotating Control Device and that is why e.g. 5000 PSI choke system is sufficient until the Rotating Control Device pressure rating is not higher than 5000 PSI. The MPD choke manifold can be operated manually, semi-automatically or automatically by the PC. In automatic systems, after the influx is detected, no change in flowrate is necessary. The choke automatically closes and therefore increases the backpressure at the surface to control the influx. After the influx is controlled, the annular surface pressure is adjusted to circulate the influx out of the well. *The choke system in Managed Pressure Drilling operations is a part of the drilling equipment and should not be considered as a part of well control equipment (RCD is a diverter, not a BOP)*[25].

## 1.4.3. Non-Return Valves

The drill pipe Non-Return Valve (NRV) is another key tool to conduct any MPD operation. It is used to avoid U-tubing in the drill string during connections, because any positive unbalance in the annulus pushes drilling fluid back up to the drill pipe. The drilling fluid may carry cuttings that plug the motor of MWD or even cause the blowout of the drill pipe.

That is the reason why Non-Return Valve is an essential component in each MPD applications, since very often some amount of back pressure is applied to compensate the annular friction losses during MPD operation.

Currently there are several types of Non-Return Valves (sometimes called also One-Way Valve or Float Valves) in use:

- Basic Piston Type Float;
- Hydrostatic Control Valve (HCV);
- Pump-Down Check Valve (Inside BOP);
- Wireline Retrievable Non-Return Valve (WR-NRV);


Fig. 16 Non-Return Valve (Ref. No 34.)

## 1.5. Managed Pressure Drilling – other tools

Some Managed Pressure Drilling variations require the use of other tools and technologies in addition to those mentioned before. Without those tools it would not be possible to conduct and/or control operations in some MPD variations. According to the Don Hannegan[29] and Bill Rehm[1] those tools and technologies are listed below:

- Downhole Deployment Valve
- ECD Reduction Tool
- Coriolis Flowmeter
- Downhole Air Diverter

- Nitrogen Generation Unit
- Multiphase Separation System
- Real-time Pressure and Flowrate Monitoring
- Continuous Circulation Valve
- Continuous Circulation System

### 1.5.1. Downhole Deployment Valves

Downhole Deployment Valve (DDV) is a downhole valve which allows tripping without killing the well (principle of using DDV is shown in the Fig. 17). Tripping is a significant barrier in Managed Pressure Drilling applications. Increasing demand for MPD leads the usage of downhole valves since they eliminate the time spent for tripping and killing the well. DDV is a tool which is opened and closed by equalizing the pressures below and above. This tool is also called a Downhole Isolation Valve (DIV), Casing Isolation Valve (CIV) and a Quick Trip Valve (QTV).

The main idea behind this is that: *the pipe or tubing is run into just above valve. Rams are closed and the upper wellbore is pressurized up to equal to the annulus below DDV valve and fluid pumps through the valve. At this point hydraulic pressure is applied to the "open" line, driving down the protective seal mandrel and opening the valve*[1]*.* It is important to mention that the DDV is not pressure equalized, but is a power-open, power-closed device. The pressures must be equalized before opening.

Downhole Deployment Valves - advantages:

- no need to kill the well during tripping (formation damage significantly reduced);
- eliminates time required to circulate kill fluid into and then out of the well;
- protect against potential swabbing and kick while tripping;
- no fluid loss;
- eliminates the need for snubbing operations improving safety issues;
- pipe can be tripped at conventional tripping speeds, reducing rig-time requirements and improving safety for the rig personnel;
- allows for installation of long complex assemblies (e.g. whip-stocks, slotted liners or expandable sand screens);

Downhole Deployment Valve – constraints:

- it contains elastomeric seals which can deteriorate when exposed to well conditions (DDV should not be used on a long term basis);
- hole size or previous casings needs to be a size larger;
- pressure limits on the tool must be considered**;**

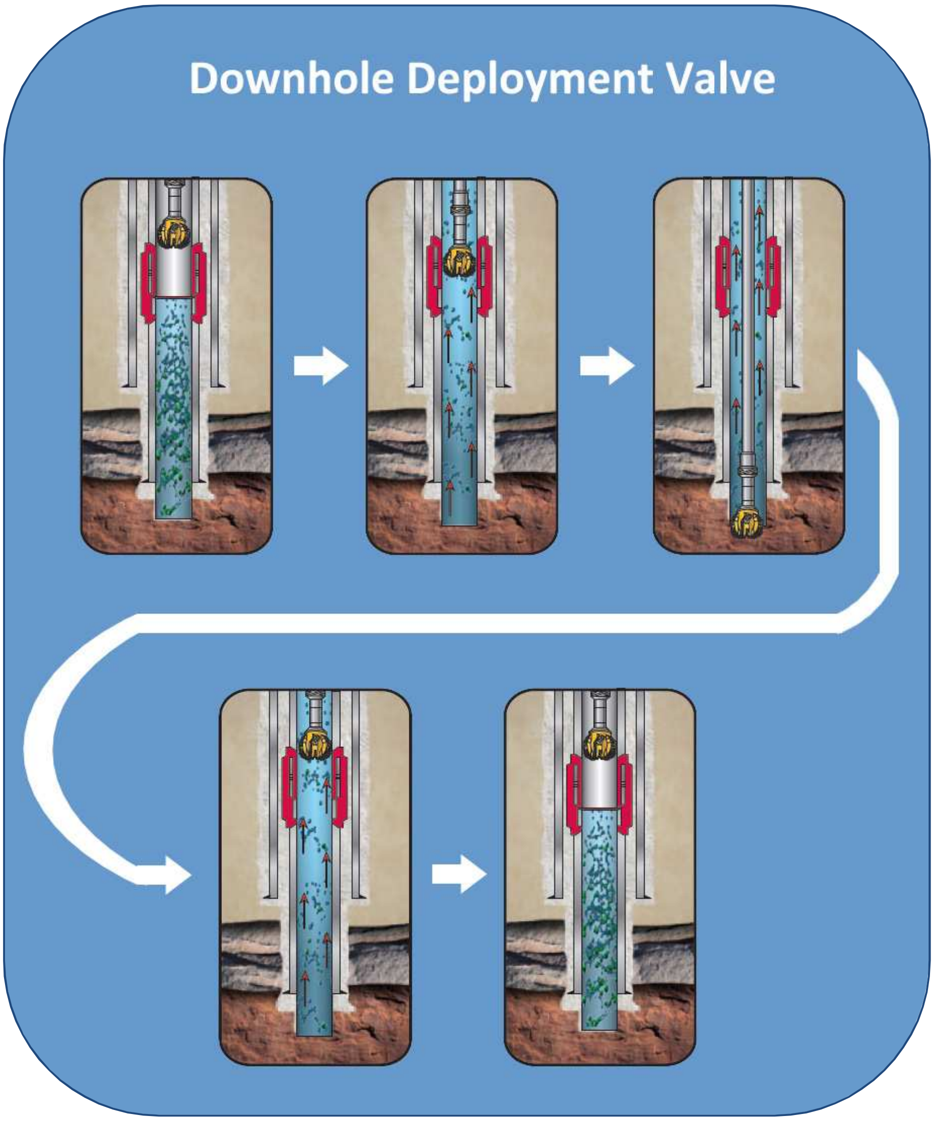


Fig. 17 Basic principle of using Downhole Deployment Valves (Ref. no 34.)

## 1.5.2. ECD Reduction Tool

ECD Reduction Tool (ECD-RT) is designed to reduce BHP increase caused by friction in the annulus by providing a pressure boost up annulus (pressure boost decreases the dynamic BHP enabling then pressure not to exceed frac gradient). Reducing ECD value is important because high ECD can cause problems in complex wells, reducing operating margin between the pore and fracture pressure. ECD-RT has three basic parts. In the top section there is a turbine motor, powered by the circulating fluid. In the middle section there is a mixed flow pump (partly axial and partly centrifugal), which pumps the fluid up the annulus. In the bottom section there are: a bearing and seals (two non-rotating packer-cup seals in the lower section which provides seal between the tool and casing).

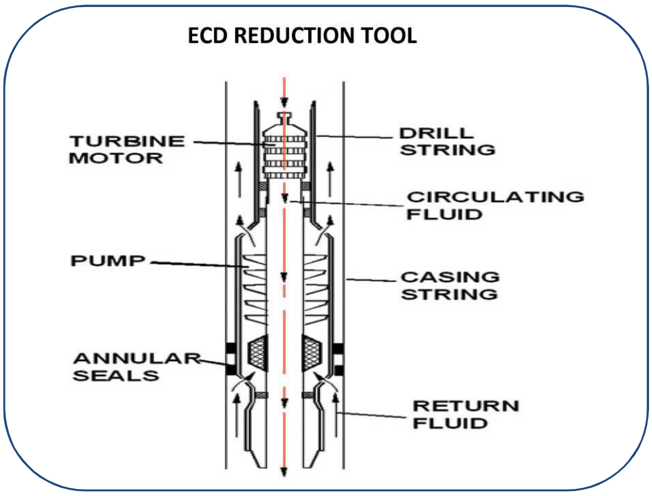


Fig. 18 ECD Reduction Tool
(Source: http://www.epmag.com/Magazine/2008/10/item11972.php)

## 1.5.3. Coriolis Flow Meter

Coriolis Flow Meter is a high accuracy mass flow meter, which measures changes in vibration patterns as the mud flows (mass flow), temperature of mud and the density of mud. Measuring principle is based on control generation of Coriolis forces. Suitable installation of Flow Meter avoids the gas and solids accumulation and it is perfect for laminar flow measurements. Coriolis Flow Meter provides supplementary data when automated pressure control systems are used.


Fig. 19 Coriolis Flow Meter (Ref. No 34.)

## 1.5.4. Downhole Air Diverter

The Downhole Air Diverter (DHAD) is a drill pipe or drill collar sub equipped with two sonic nozzle valves placed in the drill string to divert a portion of the compressed pneumatic fluid from inside the drillstring into the annulus. Depends on the MPD application and the specific purpose it can be one or more diverter subs in the drill strings.

*DHAD has been able to increase the efficiency of the compressed air system improving drilling performance in most drilling situations where pneumatic fluid is used for cuttings removal by a more efficient use of the compressed air's energy. Since the tool reduces the losses in BHA by diverting the flow, the efficient use of energy is gained*[1].

Downhole Air Diverter – advantages:

- less annular BHP;
- less surface drill pipe pressure;
- reduction or elimination of low velocity zones;
- reduction of erosion potential through BHA;
- reduction of downhole fire potential;
- aids in use of hammer tool and flat bottom bit to control angle;

## 1.5.5. Nitrogen Generation Unit

Nitrogen Generation Unit (NGU) produces nitrogen from air using a filtering process. Air is first compressed and then cooled. After that air enters couple of filters to remove particulates and water vapor and dried and pure air proceeds to oxygen filter membrane, which separate nitrogen from the air (oxygen is vented to the atmosphere). Nitrogen enters then a gas booster where the pressure increases to the working pressure. NGU is mainly used in remote locations (when providing nitrogen to the rig takes long time) with Dual Gradient MPD variation.

Fig. 20 Nitrogen Generation Unit (Ref. no 34.)

## 1.5.6. Multiphase Separation System

Separators are mainly used in Dual Gradient MPD variation where gas separation is an evident subject. Separators can be also used in case of any influx to condition the drilling fluid. There are two different kinds of separators designed especially for the specific purpose:

- vertical separators are ideal for separating gas from liquid;
- horizontal separators are ideal for the separation of liquids of various densities;

Fig. 21 MPD Multiphase Separation System (Ref. no 34.)

Possibility design for the MPD applications is a dual purpose separator for the separation of formation fluids, which consists of an underbalanced drilling separator and Managed Pressure Drilling separator. By using dual purpose process, separation costs are reduced. Multiphase separation systems offer advantages for some offshore Managed Pressure Drilling applications.

## 1.5.7. Real-time Pressure and Flowrate Monitoring

Real-time measurements and flowrate monitoring not only provide invaluable data to the automated control systems, but furthermore monitor the results of the applications of emerging concepts. Managing the Bottom-Hole Pressure accurately within a narrow pressure window helps to mitigate the risk of serious drilling events and improves drilling performance and well control.  In Managed Pressure Drilling, flowrate measurements are used to mitigate potential well control risks by:

- early kick detection by detecting, as early as possible, the influx of fluids from permeable or fractured formations into the well;
- detection of lost circulation by detecting the loss of drilling fluid from the well into permeable or fractured formations;

### 1.5.8. Continuous Circulation Valve

Continuous Circulation Valve (CCV) is two-position, three-way ball valve, which enables Continuous Circulation Method sub-category of a Constant Bottom-Hole Pressure MDP variation. CCV was initially designed to enable drilling in depleted reservoirs at High Pressure/High Temperature fields (there are many of those on the Norwegian Continental Shelf). In this system to get a circulation during the whole drilling operation, downhole pressure has to be constant even during jointed pipe connections. Downhole pressure is balanced between maximal value of pore pressure and minimal value of frac pressure, therefore drilling can be performed even in very narrow pressure windows. Mud can be designed for dynamic conditions because during continuous circulation wellbore is never under static condition. It is possible to circulate through the valve from the Top-Drive down through the drillstring or through a side port down the drill string. This valve has to be installed before starting continuous circulation operation at the top of each drill pipe stand. During making a connection, hose has to be connected to valve side inlet, the flow from the mud pumps is switched then from the top inlet to the side inlet, Top-Drive can then be disconnected and a new stand installed. To continue drilling, the operation is reversed.

### 1.5.9. Continuous Circulation System

Continuous Circulation System (CCS) is used for continuous circulation in the well even making a jointed pipe connection. During connection, the drill pipe is suspended from a pressurized chamber that comprises two pipe rams and one blind ram. This arrangement enables the circulation of drilling fluid down the drillstring to be maintained throughout the entire section. Continuous Circulation System as mentioned in section about CCV is one of the most valuable technologies in Constant Bottom-Hole Pressure MPD variation and has a wide range of applications to mitigate drilling hazards.

## 1.6. Demand for Managed Pressure Drilling in marine environments

Currently more than half of all offshore drilling prospects are economically undrillable using conventional drilling methods with conventional drilling equipment. The main reason for that are excessive costs caused by drilling related issues and problems. It can be circulation loss, differentially stuck pipe, twisting-off, kick-loss situations etc. (most of them are associated with narrow pressure windows), which cause high amount of Non-Productive Time and a lot of well control issues. All of drilling-related issues mentioned above have one thing in common – they can be avoided if wellbore pressures are controlled, maintained and managed in more precise way.

The specialized equipment necessary for Managed Pressure Drilling in offshore environments has been well proven for the more demanding practice of UBD and are applicable to all types of rigs used offshore (both fixed and floating). What is even more important a number of first applications proven that MPD technology can easily deal with a drilling in narrow pressure window, improve HSE issues, reduce significantly Non-Productive Time and associated overall drilling costs.

Managed Pressure Drilling technology leads to many present offshore hydrocarbon resources becoming available.  Therefore it is important, that MPD is and probably will be widely used in offshore drilling in next years.

## 1.7. Offshore Underbalanced Drilling vs. Managed Pressure Drilling

Underbalanced Drilling (UBD) and Managed Pressure Drilling (MPD) are both focused on the controlling Bottom-Hole Circulating Pressure while drilling but in those two methods it is accomplished in a different way. In MPD case BHP is designed to be equal or slightly above the pore pressure but in UBD case BHP is always maintained below the pore pressure and therefore induces formation influx to the well and up to the surface.

MPD is mostly applied to solve drilling-related problems (reservoir benefits sometimes can be also attained). UBD is applied to solve both drilling and reservoir/production problems. Therefore main difference of those methods is based on the intent what is the main issue in particular case. To compare both methods it should be considered the project objective, all equipment requirements, risks and potential benefits of using each method. MPD is often easier to apply than UBD. Currently the main problems with underbalanced drilling are well control standards. Latter issue is that in UBD case (if multiphase flow is concerned) gas flow interferes with logging tools measurements (it is not an issue in MPD case). Other arguments against applying Underbalanced Drilling offshore are:

- wellbore instability;
- dealing with produced hydrocarbons;
- UBD equipment needs to have large space on the rig;
- regulatory requirements (as mentioned above);

Most of arguments mentioned above are not applicable to Managed Pressure Drilling, since:

- dealing with well instability in better way than in UBD;
- no more hydrocarbons are produced to the surface than in conventional drilling;
- there is no need to have all UBD equipment (required space on the rig is significantly reduced);
- HSE benefits attractive to the regulatory agencies;

## 2. Managed Pressure Drilling from floating platforms

Recent development of MPD techniques for the use from floating drilling rigs began in the late 90's simultaneously with development of 5$^{th}$ generation offshore drilling rigs. During this period a number of industry efforts focused on developing "riserless" or dual gradient drilling systems employed subsea mud return pumping system. First exploration wells using Managed Pressure Drilling technology from floaters have been drilled in South East Asia. By the end of 2010 number MPD applications like HSE MPD, Dual-Gradient, Constant Bottom-Hole Pressure and Pressure Mud Cap Drilling MPD have been employed from fixed installations with surface BOP and also from floating platforms.

With increasing number of deepwater drilling from remote locations and challenges associated with precise pressure management in deep and ultra-deep waters, Managed Pressure Drilling should be considered as a valuable alternative to conventional drilling in many deepwater drilling areas.

## 2.1. Heave compensation and station keeping

Floating drilling rigs cannot be considered as simply as a piece of real estate to hold a payload and to support risers. The dynamics of the floater can be affected by the risers and mooring system and to conduct a drilling operations properly, floating rig has to be “kept in station”, which means keeping the facility within a specified distance from a desired location. If it is not, there is a high probability that riser buckle, and if break, it could create very dangerous situation, both to the personnel and the environment. The station-keeping can be achieved by means of mooring lines (may be adjustable), by means of a dynamic positioning system (using thrusters), or a combination of those. Mooring means to provide a connection between the floating structure and the seabed to secure a floating structure against environmental loads. Heave compensation is also a key issue in each deepwater drilling application with floating rigs (especially in severe weather areas). Some heave compensation methods (tensioners) accommodate vertical motion and maintain a relatively constant tension on the riser without causing damage to the drilling rig or the riser. Other methods, like drillstring motion compensators (Bumper Subs, Heave Compensators, Traveling Block Compensators, Crown Block Compensators, Active Heave Compensators or Wire Line Compensation) have similar purpose. In order to maintain a constant weight on the bit, safely land casing, BOP stacks etc. effects of vessel motion has to be limited. The compensators are pneumatic strings; most of them operate under the same principal as tensioners.

Why is it so important regarding to deploying Managed Pressure Drilling from a floating platform? It is because in conventional drilling, operations are conducted with hydrostatic overbalance in the well. If there is a need for “drift off” (in the case of dynamic positioned rig), subsea BOP and hydrostatic pressure of the drilling fluid acts as a primary barrier. When a Managed Pressure Drilling technology with a surface BOP is used, it has to rely on a hydrostatic pressure in the well created by drilling fluid (which is in general lower than in the conventional drilling) and furthermore on the added frictional pressure applied to the well, to have the sum of hydrostatic pressure and choke pressure equal, slightly below or slightly higher than pore pressure.

## 2.2. Placement of Rotating Control Device

There are several possibilities for placing a Rotating Control Device, if drilling from a floating platform (Semi-Submersible, Drillship etc.). Rotating Control Device can be:

- Installed above the Slipjoint with the Slipjoint collapsed and locked;
- Installed above the Slipjoint with the Slipjoint inner barrel removed;
- Installed below the tension ring and Slipjoint;
- Installed at the Subsea stack below the Low Marine Riser Package (LMRP);
- Install installed at surface, with the BOP Stack;

Main characteristics of each configuration (according to the Steve Nas, 2010; Ref. no 23.), benefits and constraints will be discussed further in the Sub-chapters 2.2.1-2.2.5.

### 2.2.1. Install the RCD above the Slipjoint with the Slipjoint collapsed and locked

Rotating Control Device can be placed above the Slipjoint with its collapsed and locked. RCD placement in that configuration indicates that max. surface pressure is limited to the pressure at the Slipjoint seal and heave effects is not compensated by the Slipjoint. Furthermore conventional drilling applications require that seals of Rotating Control Device installed to have circulation back to the flowline (or multi-segmented upper Slipjoint have to be fabricated).

### 2.2.2. Install the RCD above the Slipjoint with the Slipjoint inner barrel removed

Rotating Control Device above the Slipjoint with the Slipjoint inner barrel removed. Then maximum surface pressure is limited by the riser pressure. Heave and current effects are compensated by the Slipjoint. As in the configuration above conventional drilling applications require that seals of RCD installed to have circulation back to the flowline. Furthermore MPD equipment can be changed without pulling the riser.

### 2.2.3. Install the RCD below the tension ring and Slipjoint

In that configuration maximum surface pressure is limited by the riser pressure rating. Heave (or current) effects are terminated on the Slipjoint. Conventional Drilling can be done with bearing assembly removed. Riser has to be pulled if there is an issue with Rotating Control Device. Termination joint for kill, choke, booster and solid conduit lines has to be changed below the RCD (or bypass systems has to be fabricated for the Rotating Control Device).

### 2.2.4. Install the RCD at the Subsea stack below the LMRP

If the Rotating control Device is installed at the Subsea stack below the Low Marine Riser Package, then maximum surface pressure is limited by the Rotating Control Device. Heave (or current) effects are not an issue but BOP stack has to be pulled if there is a problem with RCD. In that configuration return flow from the well has to be pumped up through a special line to the surface. Conventional drilling applications can be done with bearing assembly removed. The main constraints regarding to placing the Rotating control Device subsea below LMRP are limited lifetime of rubber seal elements and long trips to change those elements.

### 2.2.5. Install the BOP stack with the RCD installed at surface

When the Rotating Control Device is installed at the surface with the BOP stack, then maximum surface pressure is limited by the Rotating Control Device. Moreover heave (or current) effects are not compensated by the Slipjoint and conventional drilling applications can be done with removed bearing assembly. There is also no need to pull Blow-Out Preventer stack if problems with RCD occurs. Tieback to the surface required with casing inside the riser.

## 2.3. Surge and swab effect during making connections

Surge and Swab friction pressures present because of the displacement of fluid caused by drillstring movement (piston effect) during drillstring tripping in a well filled with fluid. High surge and swab pressures may lead to the lost circulation or influx of the formation fluids. Controlling of surge and swab pressures during connections is very difficult especially if pressure window is very tight. The use of a Mobile Offshore Drilling Unit (MODU) in deepwater environments causes even higher surge and swab pressures, which are difficult to control because of the heave motion. The heave compensator on the MODU controls the position of the drillstring both in a drilling and tripping-mode. However, during make-up and break-out of the connections, drillstring is suspended in slips in the rotary table and the whole drillstring moves up and down with heave motion of the Mobile Offshore Drilling Unit. MODU heave period at the level of for example 16s requires downhole pressure changes at the level of 8s. It should be taken into consideration also delay before the pressure and/or flowrate change initiated on the surface reaches the drill-bit depth. Therefore, pressure model has to predict the downhole pressure behavior vs. time and the surface parameters has to be continuously adjusted.

## 2.4. Excessive casing strings

In deepwater and ultra-deepwater areas, the problem of necessity of excessive casing program often occurs, because of the pressure from the drilling fluid in the riser. With deeper holes, normally, the mud density in the riser increases, increasing the differential pressure between the fluid in the riser and the seawater outside of it. The typical solution is simply to run more casing strings. Several efforts are ongoing to use a modified mud column in the riser to resolve this problem. Excessive casing program is one of the main challenges of conventional drilling in deepwater environments, which can be overcome by utilizing Managed Pressure Drilling technique.

## 2.5. U-Tube effects in Managed Pressure Drilling operations

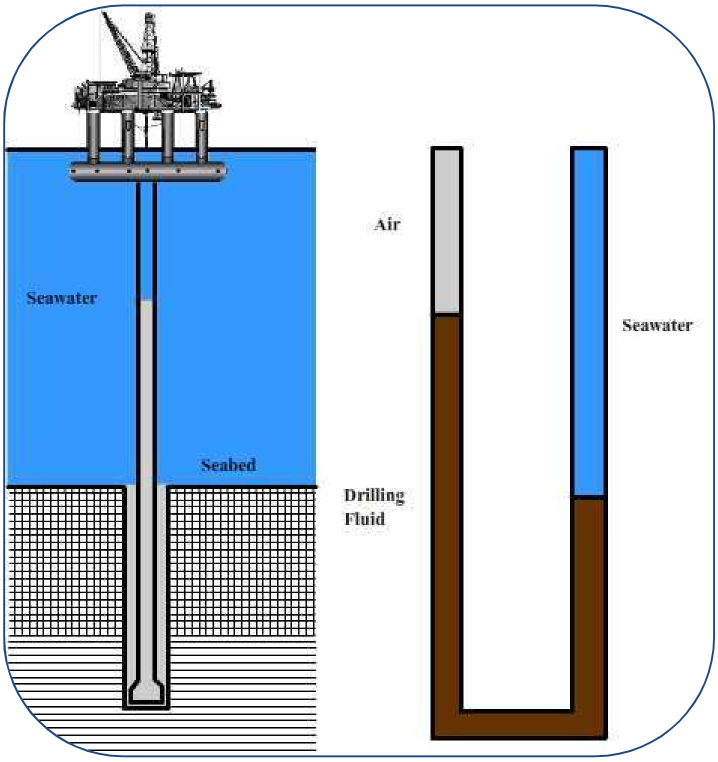

Fig. 22 U-Tube effect in deepwater drilling

U-Tube effect on connection happens when the pump is turned off. While static conditions, hydrostatic pressure of the drilling fluid balances the hydrostatic pressure of the seawater (if drilling riserless or using a subsea pump). Due to drilling mud is heavier than seawater a lower height of drilling mud is necessary. Additional mud from the drill pipe is pumped to the mud pits by the subsea pump or dumped to the seabed.

After some amount of time, stabilization between the hydrostatic pressure of drilling mud and the seawater is attained. The discharge rate of the drilling mud to the seabed depends on the mud properties, water depth, and geometry of the well.

U-Tube effect can be dangerous, because it masks the start of a well-kick on a connection or when the pump is slowed down. Furthermore, connection gas may mask the beginning of a problem (air from the empty drill pipe is mixed in the annulus).

## 2.6. Wellbore control

In deepwater drilling margins between pore and fracture pressure generally are smaller than on land rigs or in shallow water. Therefore one of the key challenges in conventional deepwater drilling and in Managed Pressure Drilling in particular, is to mitigate and operate within this very narrow pressure window. Moreover in harsh environment with considerable rig movement (heave) the pressure transients created by rig heave can affect the downhole pressure control. This effect will particularly come into play every time slips are set on the drill pipe, for example during connection. Currently very accurate flow meters in combination with also very accurate stand pipe pressure sensors to monitor pressure and flow changes over time and therefore detecting a potential kick. Flow measurement can be done in a three ways: by measuring volumetric flow (directly measures volume of the fluid passing through the meter), by measuring velocity flow (measures velocity include magnetic, turbine, ultrasonic, and vortex shedding and fluidic flow meters), by measuring mass flow (Coriolis Flow Meters).

When dealing with a kick there are two main factors describing its:

- Kick intensity: The pore pressure/wellbore pressure differential driving a well kick must be predicted by the operator using geology history, or drilling data and casing set before the pore pressure exceeds the up-hole fracture pressure;
- Influx volume: This is a matter of quick response or detection;

According to the IADC definition of MPD "any influx incidental to the operation will be safely contained using appropriate process". With Managed Pressure Drilling system installed there are two choices to circulate out of the influx.

- Using MPD equipment and a Choke Manifold (with the MPD Choke Manifold it is possible to continue circulating, increase the back pressure on the well until the flow in and flow out are balanced and then circulate out the influx using the driller's method);
- Using BOP's and rig Choke Manifold (when detecting a kick, a conventional well control procedures can be used -this process is established as follows: at first drillstring is pulled up and spaced out, then the pumps are stopped, after that BOP will be closed, then Shut-In Drill Pipe Pressure and Shut-In Casing Pressure will be recorded);

## 2.7. Annular pressure changes (ECD problems)

In dual-gradient system the same annular pressure loss problems occurs as in any other drilling operation. When the pump is turned off, value of the bottom-hole pressure (BHP) drops. When pipe is picked up for a connection, the bottom-hole pressure drops a bit more.

The opposite effect occurs when running pipe in the hole or turning the pump on. Surging on a floater may also have some slight annular pressure effect.

## 2.8. Wellbore ballooning

Wellbore ballooning occurs in elastic marine sediments when fracture pressure is exceeded. Wellbore ballooning can be explained as a temporary storage of drilling fluid in the formation due to increased wellbore pressure. Typically loss is seen when starting the mud pumps, and a subsequent gain in seen when the pumps are shut down. In other words wellbore ballooning can be described as taking drilling mud when the pumps are on and giving the mud back from the formation when the pumps are off. The determination of ballooning depends on accurate measurement of a very small flow when the pump is turned off. While it occurs in drilling with dual-gradient systems, it is difficult to measure; procedures with the subsea pump furthermore may tend to mask a very minor flow from the annulus. Therefore it is difficult to differentiate the wellbore ballooning from the influx/loss situation. In the case of "pump and dump", ballooning is even more difficult to measure.

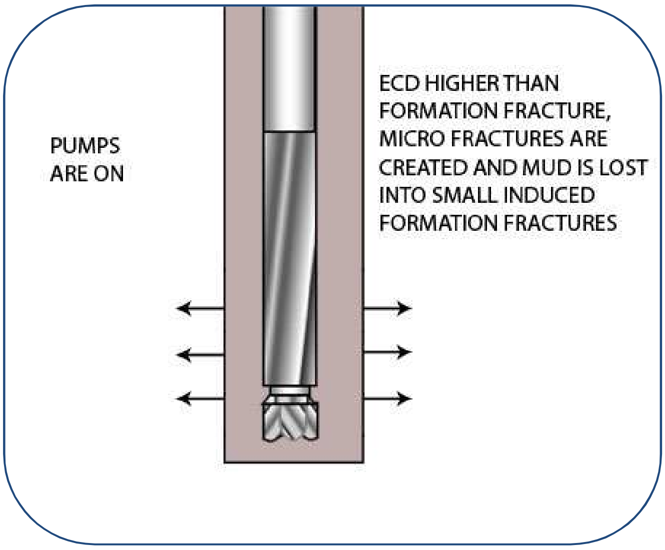

Fig. 23 Wellbore ballooning

## 2.9. Time to detect influx

In conventional deepwater drilling from a floater an influx can be masked by the slipjoint (heave), moderate accuracy of the sensors and obviously depends on the crew experience. In the Managed Pressure Drilling case the whole automatic kick detection and control system is very rapid - can detect even less than 1/4 [bbl] influx almost immediately.

## 2.10. Recent experiences with MPD from floaters

Floating application of the Managed Pressure Drilling is still very new in petroleum industry but by the end of 2011 (mostly PMCD and DG variation) has been utilizing in many places all over the world. Some of them have been drilled:

- In Mediterranean Sea Libya - Eni successfully drilled what was thought to be undrillable conventionally. ENI used a Weatherford's RCD 7875 getting straight into the reservoir, saving money and time. To compensate the heave a 3 barrel slip joint was used, above the RCD;
- By Reliance India - Pride North America successfully drilled a well in MPD mode using RCD 7875;
- By Talisman Indonesia - Plan to utilize RCD 7875 for a well, using a drillship in dynamic position;
- By Noble Energy E.G. - MPD multi-well deepwater project drilled in 2010;
- By Sarawak Shell - 3 wells drilled from a semi-submersible Stena Clyde and 2 wells from a semi-submersible Ocean Epoch in carbonate formations in Offshore Malaysia using Pressurized Mud Cap Drilling variation;
- By Sarawak Shell - 8 wells drilled on 3 fields using Pressurized Mud Cap Drilling from a Semi-Tender West Alliance in Offshore Malaysia
- By Santos - 11 wells drilled from a Semi-Submersible drilling rig (SEDCO 601) offshore Indonesia using Pressurized Mud Cap Drilling variation

Based on the recent experiences from those mentioned above and other practices, it has been found that[23]:

- Heave does not have a significant impact on the life of RCD rubbers;

- Rig offset must be monitored (on most floaters with subsea BOP – standard procedure);

- Installing the flow spool and RCD together gas proven to safe time during rig up;

- Drill pipe condition have a significant impact on the rubber life;

- Severe weather while rig up operations may require riser slipjoint to be pinned and supported from the moonpool to allow safe installations;

# 3. Review of the Skarv/Idun field development

Skarv and Idun fields are located in the Norwegian Sea (about 200km west Sandnessjøen), between the Norne and Heidrun fields in water depth between 350 and 450m. Skarv sits in the production license no. 212 and was discovered in 1998. Hydrocarbons have been encountered in the Jurassic Garn, Ile and Tilje reservoirs and in the Cretaceous Lange sandstones. Appraisal wells showed that oil lies mainly in the Garn reservoir (southern part of Skarv field) and in the Tilje formation, whereas gas lies in northern part of the Skarv field and in the Ile formation. Garn formation is a high quality reservoir, but substantial hydrocarbons are also present in the poorer quality Tilje and Ile reservoirs.

Operator of the Skarv/Idun field is BP (23,835%). Other licensees are: Statoil with 34,11%, Shell with 28,0825%, PGNiG Norway AS with 11,9175% and Hydro with 2,055%.

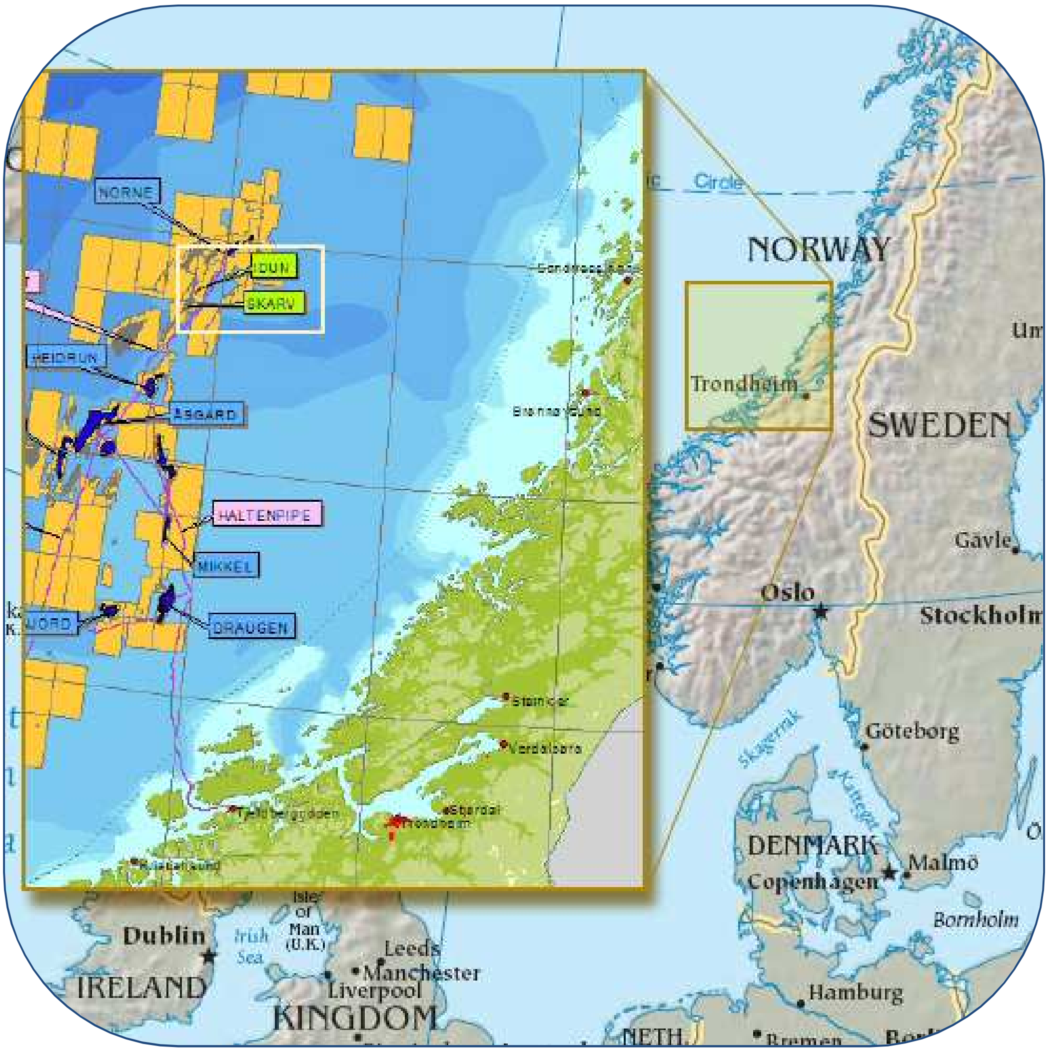


Fig. 24 Location of the Skarv and Idun fields (Source: Skarv Idun PDO/PIO; Ref. no 31.)

## 3.1. Overview of the Skarv/Idun field development

As mentioned before Skarv/Idun field contains hydrocarbons at four reservoir levels (Jurassic Garn, Ile and Tilje and Cretaceous Lange). 80% of total recoverable resources are gas, remaining 20% are liquids. Total recoverable resources basis is estimated to be 16,8 million cubic meters of oil and condensate and 48,3 billion cubic meters of rich gas.

### 3.1.1. Field development concept

Skarv/Idun field is oil and gas field developed subsea (subsea wells, templates and flow lines) utilizing a standalone turret-motion Floating, Production, Storage and Offloading (FPSO) vessel with offshore oil loading to the shuttle tankers and a gas export via the pipeline connected to the Åsgard Transport System pipeline, which will transport gas to Kårstø.

The FPSO has the capacity for oil production at the level of 85 000 BPD, for water production of 20 000 BPD and for gas production of 670 MMscfd.

The development is based on the high rate oil and gas production wells with sand control completions. Pressure support for oil depletion will be provided by high rate gas injection wells. Gas injection is preferred over water injection as it offers improved hydrocarbon recovery, better economics, and poses less risk to life cycle well operability.

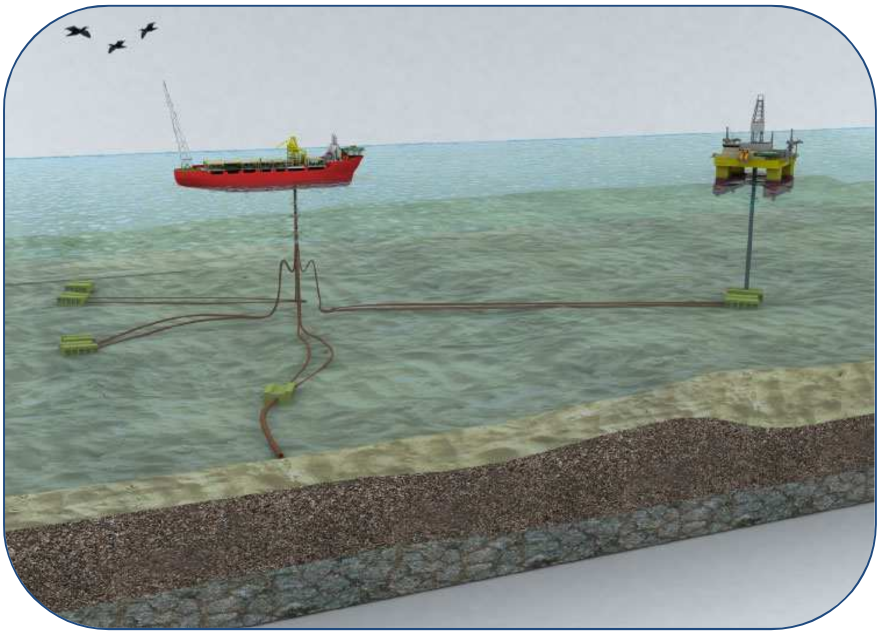

Fig. 25 Skarv/Idun development concept with FPSO and semi-submersible drilling rig
(Source: Skarv Idun PDO/PIO; Ref. no 31.)

## 3.1.2. Regional geological setting

The Skarv and Idun fields lie on a narrow fault-bounded terrace that forms part of the Dønna Terrace in the Norwegian Sea. Situated between the Trøndelag Platform to the east and the Rås Basin to the west, this portion of the margin represents the hanging-wall blocks of the major structural high forming the Nordland Ridge. The present configuration of this part of the North Atlantic Margin is the result of a long and complex structural evolution. The key elements of the tectonic evolution directly influencing the Skarv/ Idun region are:

- Permo-Triassic extension and thermal subsidence acting on a complex Caledonian basement template;
- Jurassic thermal subsidence and extension;
- Cretaceous thermal subsidence, extension and local transtension;

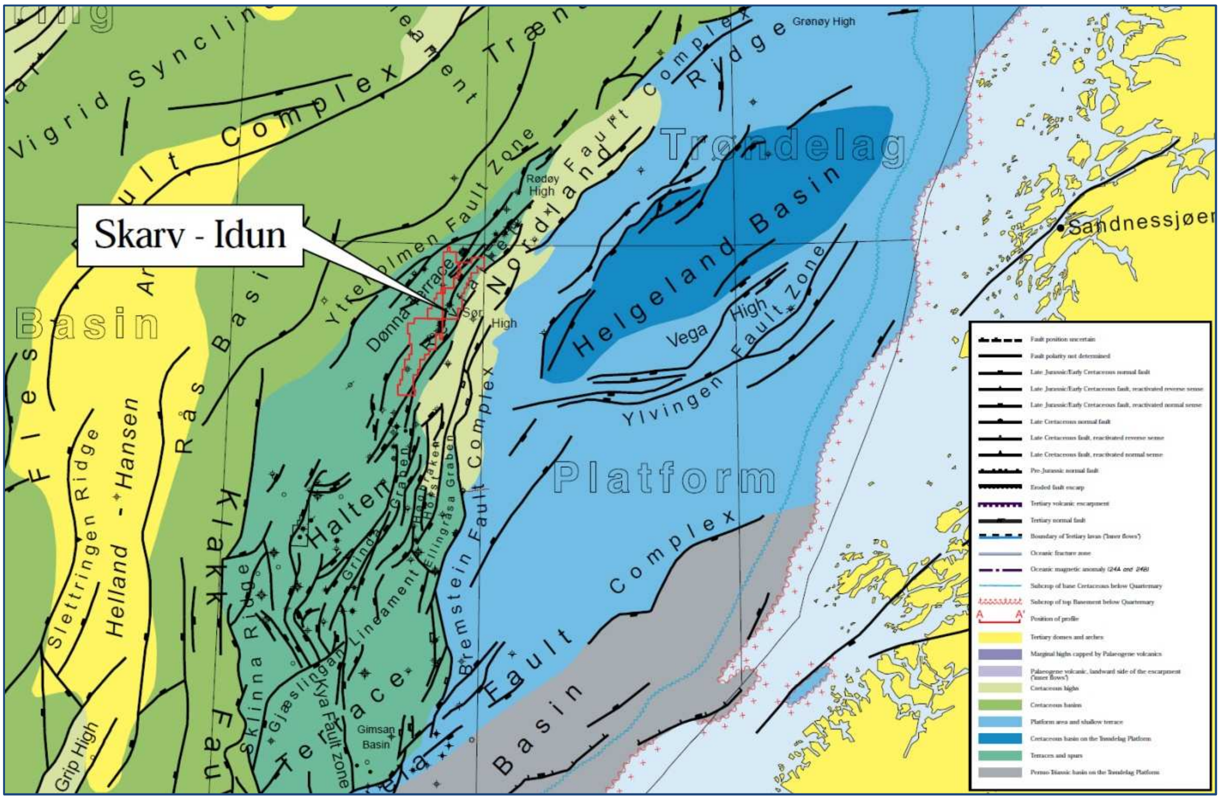


Fig. 26 Regional Structural Elements and location of Skarv/Idun fields (Source: Skarv Idun PDO/PIO; Ref. no 31.)

### 3.1.3. Geology prognosis

Most of the wells has targeted the Jurassic Garn sandstone formations, containing both oil and gas reserves. One well (6507/5-3) was drilled into the shallower Cretaceous sands of the Lysing and Lange formations in the Snadd area. In different template locations there is a significant difference in water depth which has an impact on the overburden and fracture estimates. Geological description for the lithology groups and formations in the Skarv/Idun area are described below (some of the formations may not be presented in all wells). As a reference was used well 6507/5-5 for the generic depth of the various formations (depths are in m below Mean Sea Level).

**Nordland Group (seabed – 1375 m)**

The Nordland Group consists of the Naust and Kai Formation which are upper glacial deposits. It consists mainly of silty to sandy clay and clay stones, with inter-bedded sands and clays and occasional limestone stringers. Towards the bottom of the Kai Formation the clay becomes cleaner.

**Hordaland Group (1375 – 1870 m)**

The Hordaland Group is made up by the Brygge Formation being a marine deposit. It consists of silty to sandy clay stone with stringers of sandstone and limestone in the middle part of the formation. Tuffaceous clay stone has been recorded in the lower and partly in the middle part. Limestone is present in the formation, particularly in the upper part.

**Rogaland Group (1870 – 2045)**

The Rogaland Group is made up of the Tare and Tang Formation being marine deposits. The Tare and Tang Formation consist predominantly of clay stone with thin stringers of limestone and occasionally dolomite.

**Shetland Group (2045 – 2540 m)**

The Shetland Group is made up by the Nise and Kvitnos Formation. The Nise Formation consists of mudstones with commonly dolomite stringers, while the Kvitnos Formation consists of mudstone with common limestone stringers.

**Cromer Knoll Group (2540 – 3308 m)**

The Cromer Knoll Group is made up by the Lysing and Lange Formation. Not all the exploration wells have encountered the Lysing and Lange Formation in the Skarv and

Idun area. The Lysing Formation consists of fine-grained, argillaceous sandstone. The Lange Formation consists of mudstone with fine-grained sands and limestone stringers. The Lysing and Lange Formation are considered secondary targets, and will be further appraised during the development drilling.

**Viking Group (3308 – 3353 m)**

The Viking Group is made up by the Spekk and Melke Formation. The Spekk Formation consists of organic rich clay stone with traces of limestone and dolomite. The Melke Formation consists of mudstone with silty intervals and frequent stringers of dolomite. Stringers of limestone occur less frequently. Only traces of sandstone and sand occur in this formation.

**Fangst Group (3353 – 3723 m)**

The Fangst Group is represented by the Garn, Not and Ile Formation. The Garn Formation is dominated by thick sandstone. The upper part of the Not Formation is consisting of sandstone, gradually fining downwards to siltstone. The lower part of the Not is predominantly clay stone with traces of dolomite. The Ile Formation consists of argillaceous sandstone with minor inter-bedded clay stone stringers in the upper part. The Garn Formation represents the main reservoir for the development.

**Båt Group (3723 – TD)**

The Båt Group is represented by the Ror, Tilje and Åre Formation. The Ror Formation consists of sandstone and thin shale layers at the top, whereas the lower part of the Ror Formation consists of siltstone, grading to sandstone and silty sandstone. The Tilje Formation is predominantly sandstone with rare, thin inter-bedded mudstone layers. The Åre Formation consists of inter-bedded sandstone, clay stone/shale and dolomite rich limestone with traces of coal. The Tilje Formation will be developed in the Skarv A segment as it contains hydrocarbons.

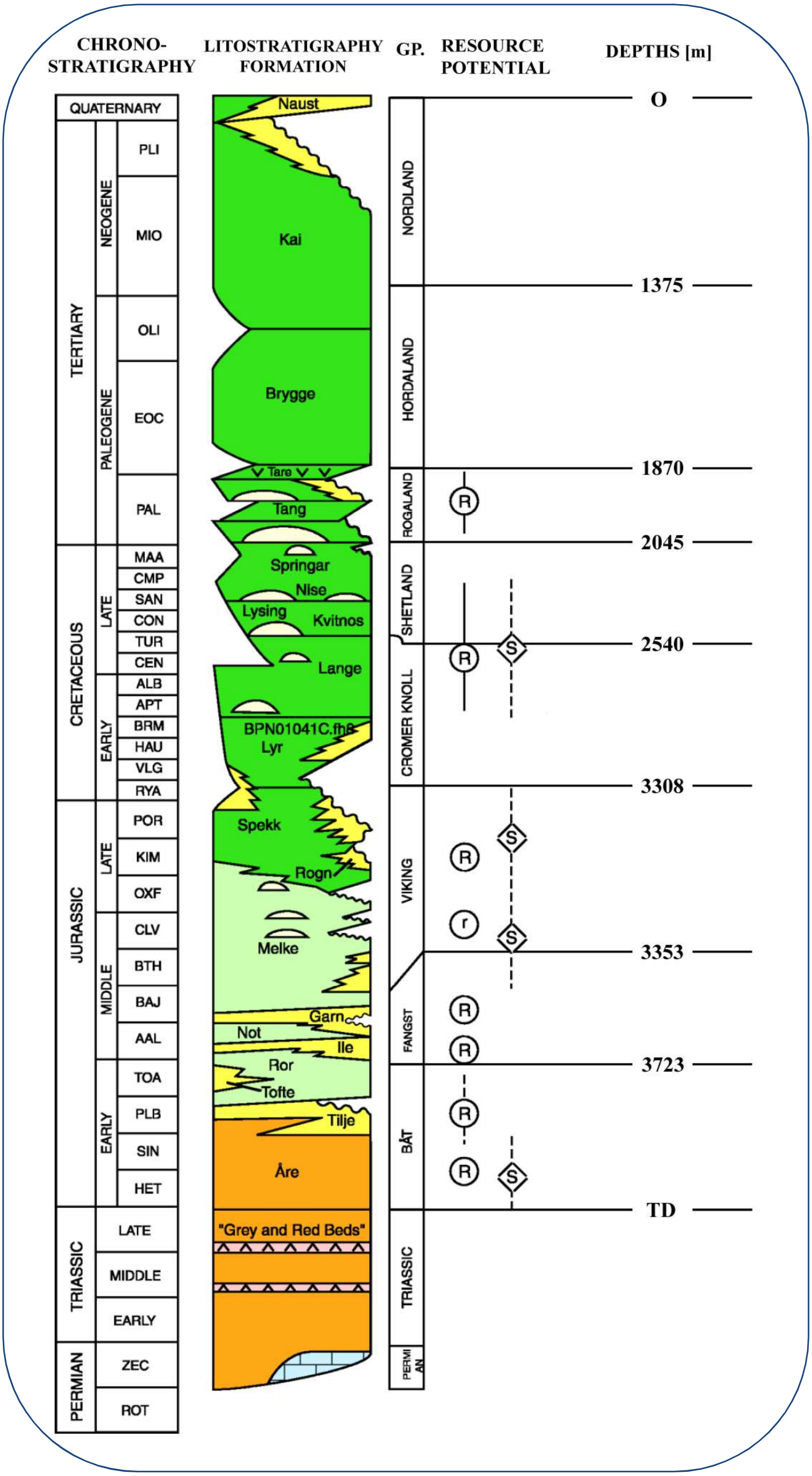


Fig. 27 Source rock distribution in the Skarv/Idun area (Source: Skarv Idun PDO/PIO; Ref. no 31.)

## 3.1.4. Wells and wellbore trajectories

A Skarv/Idun field is situated on the Donna Terrace as tilted Jurassic fault blocks and was discovered by the well 6507/5-1 in 1998. Field will be developed using 16 wells (wells concept shown in the Tab. 4). There is a plan to drill 4 or 5 gas producers, 1 gas injector and 1 or 2 oil producers prior to the production start. Rest of them (producers & injectors) will be drilled between by the end of 2012. Drilling has started in June 2009 and planned start-up of production is August 2011 (wells drilled so far are shown in the Fig. 24). The selected design life for the Skarv Idun facilities is 25 years.

| Well | Year | Status | Reservoir |
|---|---|---|---|
| 6507/5-1 | 1998 | Gas and Oil | Garn, Ile, Tilje, Lange |
| 6507/5-2 | 1999 | Gas | Garn |
| 6507/5-4 | 2001 | Gas and Oil | Garn |
| 6507/5-4A | 2001 | Oil | Garn |
| 6507/5-5 | 2002 | Oil | Garn |

**Tab. 2 Exploration wells in the Skarv field (Source: Skarv Idun PDO/PIO; Ref. no 31.)**

| Well | Year | Status | Reservoir |
|---|---|---|---|
| 6507/3-3 | 1999 | Gas | Garn, Ile, Tilje |
| 6507/3-3A | 1999 | Gas | Garn |
| 6507/3-3B | 1999 | Gas | Garn, Ile |

**Tab. 3 Exploration wells in the Idun Field (Source: Skarv Idun PDO/PIO; Ref. no 31.)**

| Formation | Field/Segment | Well Type | Template Configuration | Template (Slot) Code | Spare slots |
|---|---|---|---|---|---|
| Garn/Ile | Idun | 2 GP | 4-slot | D (1-4) | 2 |
| Garn/Ile | Skarv A | 3 GP | 6-slot | A (1-6) | 3 |
| Tilje | Skarv A | 2OP+2GI/GP | 4-slot | J (1-4) | 0 |
| Garn | Skarv B | 2OP+1GI/GP | 6+4-slot | B (1-10) | 3 |
| Garn | Skarv C | 3OP+1GI/GP | | | |
| **Total Wells** | | **16** | **24-slots** | **4** | **8** |

**Tab. 4 Subsea Development plan for wells; GP-gas producer, OP-oil producer, GI-gas injector**
(Source: Skarv Idun PDO/PIO; Ref. no 31.)

As shown in the Tab. 4 Idun field will be developed with 2 gas producers (vertical or near vertical). Skarv A Segment will be developed with 3 deviated gas producers; these wells will also be deepened through the Tilje reservoir to gather more data for optimizing the subsequent Tilje drilling program. Appraisal of Gråsel (Cretaceous) will also be done on these wells. The Skarv C segment will be developed with 1 deviated gas injector and 3 horizontal oil producers. The (C2) oil producer will have a pilot hole to determine the Oil Water Contact as well as appraise the E segment. The (C4) oil producer will be the last C oil producer to be drilled to give time for reservoir information and this well will also include a high angle pilot hole that may also appraise Snadd North in addition to measuring pressures and saturations in the C segment. The Skarv B segment will be developed with 1 deviated gas injector and 2 horizontal oil producers. The plan is to alternate drilling between the Skarv C and B segment wells. The Tilje reservoir will be developed by 2 pairs of deviated gas injectors and horizontal oil producers.

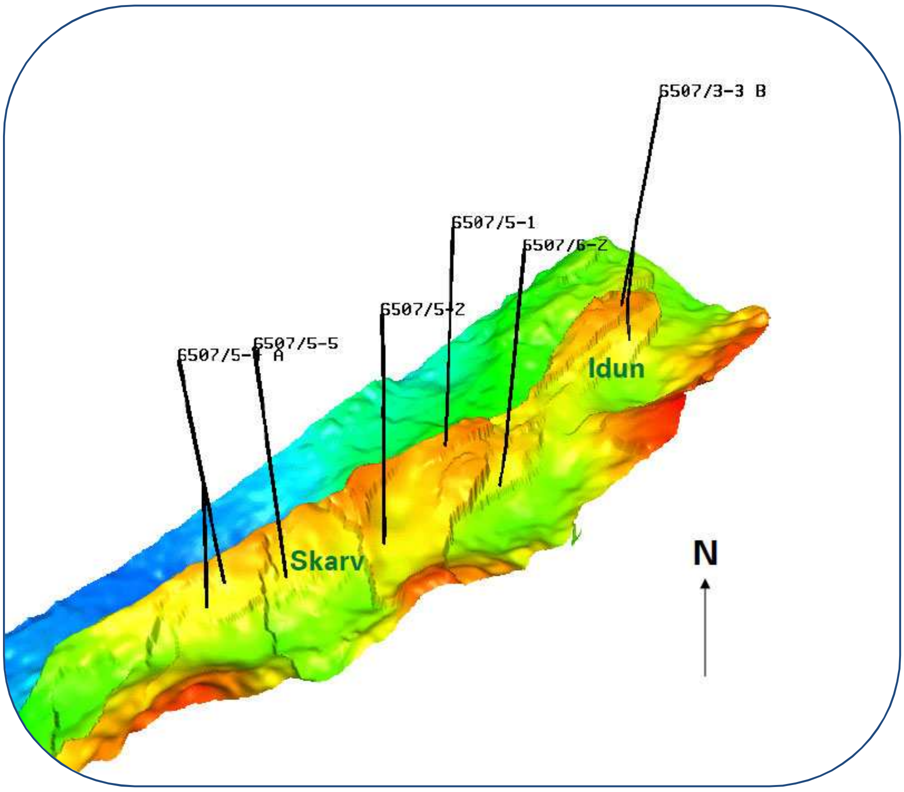


**Fig. 28 3D view of the Skar/Idun field with exploration wells**
**(Source: Skarv Idun PDO/PIO; Ref. no 31.)**

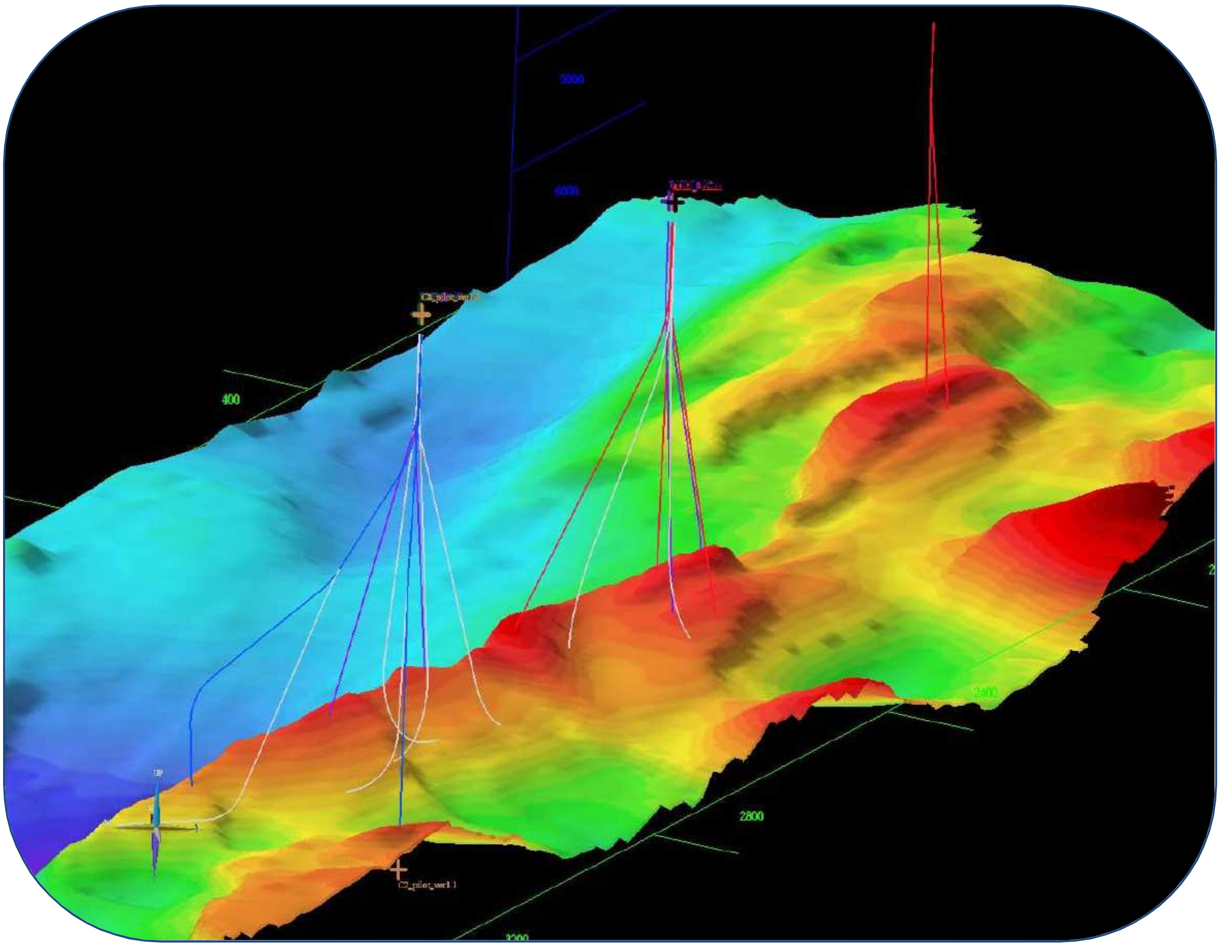

Fig. 29 Overview of the Skarv/Idun development wells (Source: Skarv Idun PDO/PIO; Ref. no 31.)

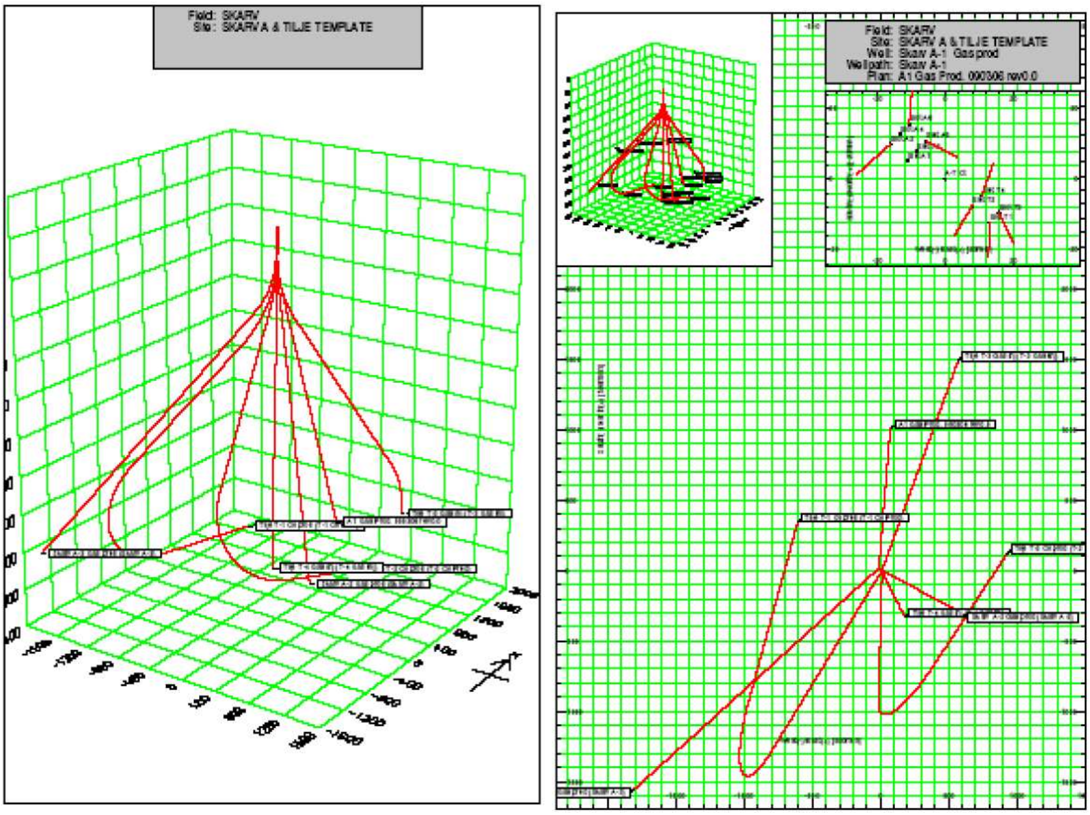


Fig. 30 Well Trajectory Overview Skarv A (Source: Skarv Idun PDO/PIO; Ref. no 31.)

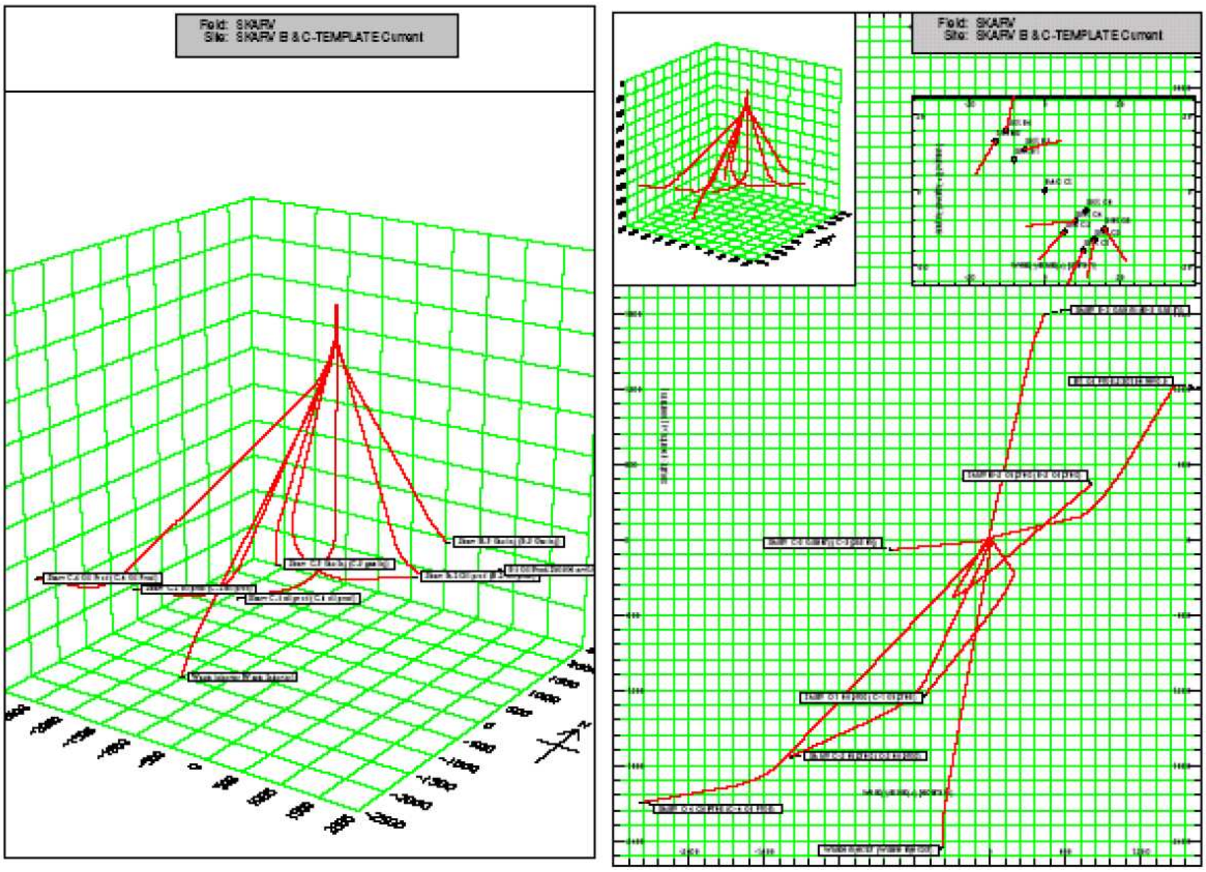


Fig. 31 Well Trajectory Overview Skarv B & C (Source: Skarv Idun PDO/PIO; Ref. no 31.)

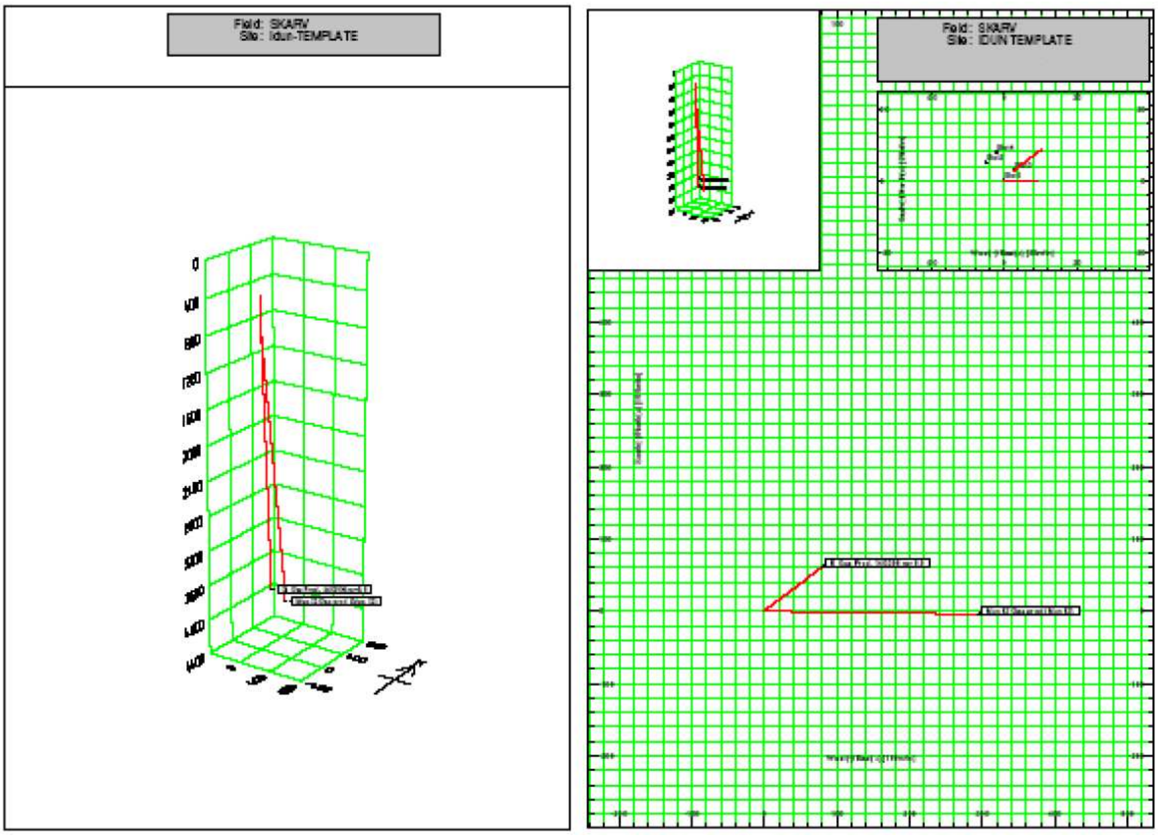


Fig. 32 Well trajectory overview for the 2 gas producers on Idun (Source: Skarv Idun PDO/PIO; Ref. no 31.)

## 3.1.5. Pore pressures, temperature and fracture gradients

Pore pressures within the Skarv Field itself are close to normally pressured with less than 200 [psi] (less than 1.1 [sg]) over-pressure. Pore pressure measurements in the overburden above the Skarv Field are limited to the Cretaceous Lysing & Lange formation sands which have 1000-2000 [psi] (1.3-1.6 [sg]) over-pressure.

Over-pressure build-up is initiated within the shales of the Tertiary Kai formation about 1400-1500 [mTVDss]. Build-up of over-pressure continues down through the Oligo-Eocene Brygge shales to a maximum of +1200psi (about 1.45 [sg]) over-pressure at the base of the Paleocene Tare and Tang tuffaceous intervals about 2000-2100 [mTVDss].

Estimates of over-pressure gradually reduce within the shales of the Upper Cretaceous Nise & Kvitnos formation to a local minimum over-pressure of +1100psi (1.35-1.4 [sg]) towards the top of the Lysing Fm sands about 2700-2750 [mTVDss]. Over-pressure estimates begin to climb once more through the underlying Lange formation sands and shales approaching +2000psi (about 1.5 [sg]) towards the top of the Upper Jurassic Spekk formation shales about 3200-3300 [mTVDss]. Estimates of over-pressure within the Spekk formation shales rise to +2600psi (1.6 [sg]) but caution is advised since porosity estimates in these shales are believed to be questionable due to micro-fracturing and organic content.

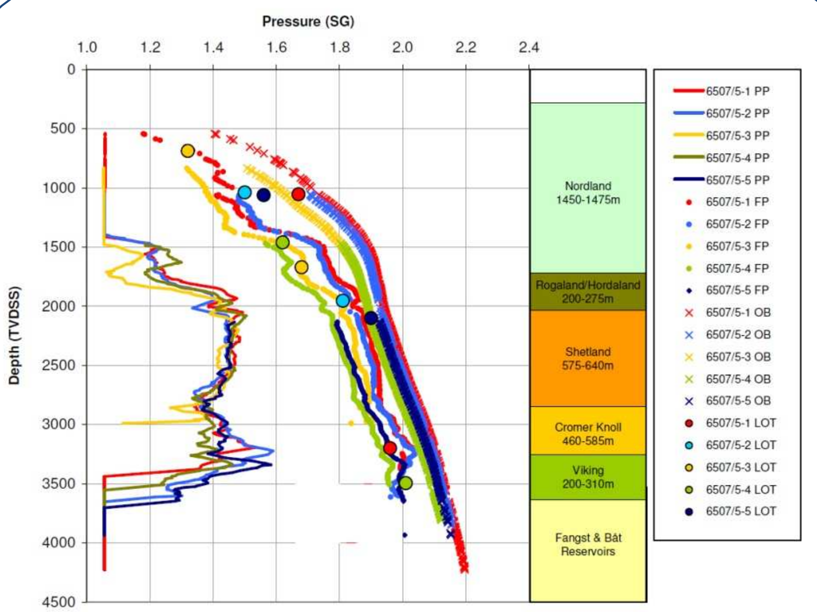


**Fig. 33 Pore, fracture, overburden and LOT pressures for the Skarv area (Source: Skarv Idun PDO/PIO; Ref. no 31.)**

Throughout the Upper Jurassic the estimated over-pressure is seen to rapidly reduce towards normal hydrostatic levels through the Melke formation shales towards the top of the Middle Jurassic Garn formation reservoir sands between 3300 and 3600 [mTVDss].

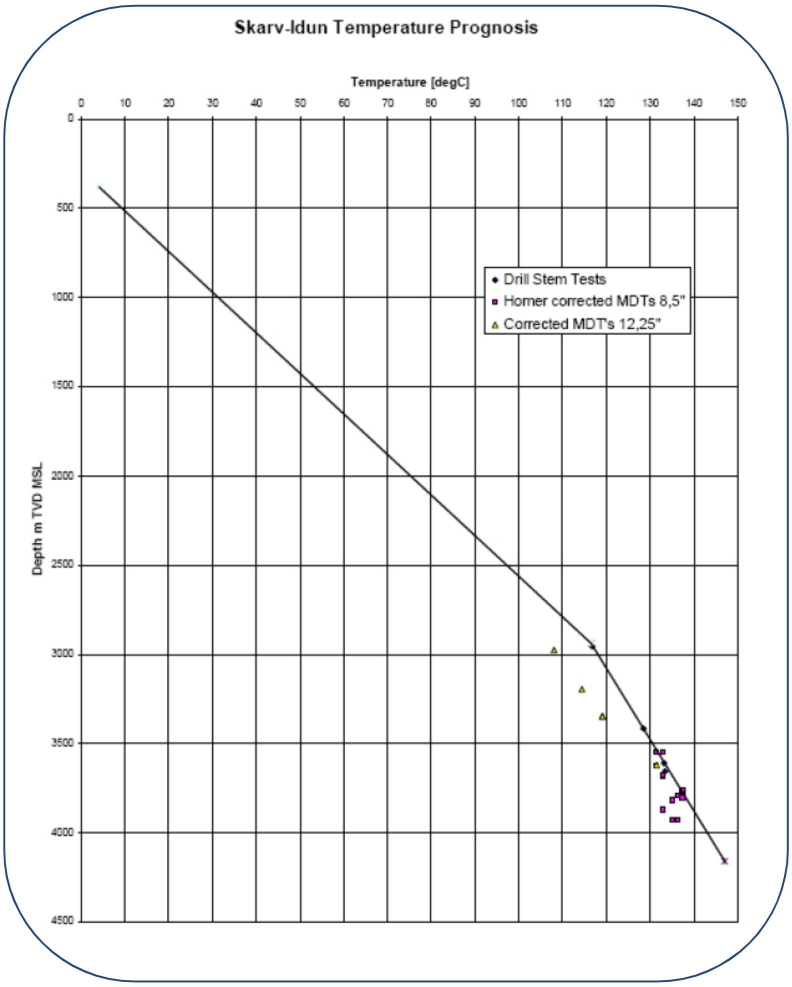


**Fig. 34 Temperature prognosis for the Skarv/Idun development**
**(Source: Skarv Idun PDO/PIO; Ref. no 31.)**

### 3.1.6. Casing design

Casing design is performed according to the NORSOK D-010 Standard and to the BP's requirements and guidelines (BP Drilling and Well Operations Policy BPA-D-001, BP Well Control Manual BPA-D-002 and BP Casing Design Manual BPA-D-003). The Skarv Idun Development will be based around a base case casing scheme, along with contingency casing schemes to account for planned changes and unplanned incidents, from either geological or technical reasons. Both the base case and contingency casing schemes have been analyzed on the basis of a generic well typical for the Skarv Idun development. Common casing weight/grade/size and connections were selected as a standard for the whole of the development field, in order to reduce stocking requirements and cost. The current base case design is a conventional 4 casing string scheme down to top reservoir consisting of:

- **30" conductor casing;**
- **18 5/8" surface casing;**
- **13 5/8" intermediate casing;**
- **10 ¾" x 9 7/8" production casing;**

The 10 3/4" section will be required to accommodate the 7" Tubing Retrievable Surface Controlled Subsurface Safety Valve (TRSCSSV) of the large 7" bore completion schemes. For 5 ½" TRSCSSV or smaller sized 5 ½" completion schemes it may be sufficient with 9 7/8" casing to surface. Currently no other liners or casings are planned as part of the casing scheme, as sand screens are planned for the reservoir section with a requirement of minimum 8 ½" size ID of the last casing and open hole.

Currently the 13 5/8" and 9 7/8" (in preference to 13 3/8", respectively 9 5/8") casing strings have been selected based on larger wall thickness, offering larger wear and corrosion allowance and much larger collapse- and axial ratings. Large collapse loading can be expected as a result of scenarios with loss of packer fluid due to packer leakage, and large depletions in oil and gas wells in later field life.

### 3.1.7. Templates and Manifolds

The Skarv and Idun development comprises 3 production centers. Field will be developed using templates and manifolds with flow lines tied back to the FPSO as opposed to cluster wells tied back to manifolds (to minimize the length of subsea flow lines and umbilicals and also reducing the number of tie-ins required). Furthermore this configuration will minimize the amount of infrastructure on the seabed and the number of rig moves required.

According to the PDO/PIO Support Documentation[30] templates should to provide:

• Interface to the conductor housing while allowing for a level adjustment to ensure an inclination of ≤1 degree relative to true vertical for each well slot. Any such level adjustment facility must consider also the interface between the drilling template and manifold module;

• Their design shall incorporate the ability to remove and transport cuttings, excess mud and cement returns away from the template during drilling of top-hole sections. This may be facilitated through either integral template facilities, and/or through the use of temporary equipment interfacing with the template;

• Their design shall allow for thermal expansion of each wellhead. The expected wellhead growth has been determined for various conditions of long term production/injection (possibly be as much as 174mm if the well is unrestrained by the template). However, due to uncertainty around soil conditions and influence of lack of cement bond/cement height around the 30” conductor and the surface casing, it is recommended to apply a factor 1.5. When the wells are restrained by the template, wellhead growth can be reduced - however template/facilities should be designed for the high restraining forces involved;

• The drilling template shall provide guidance and support to the manifold and pigging loop modules during installation and retrieval and for the BOP and Xmas Trees during installation and work-over operations;

### 3.1.8. Flowlines and Risers

The flowline and template network is modeled in the simulation model. The design consists of rigid flowlines with wet insulation for Skarv BC, Skarv A and Skarv Tilje and a wet insulation with Direct Electrical Heating (DEH) for Idun.

On Skarv A, the 3 gas producers are split between the 2 flowlines. Well GPA1 flows through one flowline, while GPA2 and GPA3 flow through the other. On Skarv BC, the Skarv B wells flow through the first pipeline while the Skarv C wells flow through the second. On Tilje each producer initially has its own flowline and later, once gas blow down starts, one producer and one converted injector are put into each flowline. On Idun there is only one flowline, so both wells flow through the same flowline.

To meet flowline operability constraints the A segment gas wells are choked back in the first year of the development and again once gas breaks through in some of the oil producing wells. This ensures that the gas rate in the Idun pipeline does not drop below 75 MMscfd/d in the early phases of the development. It does, however, delay some condensate production from Garn A, but ensures good flow assurance for the Idun pipeline system.

| Segment | Tubing size | Flowline size | Riser size | Flowline length (km) | Riser length [m] | No. flowlines |
|---|---|---|---|---|---|---|
| Skarv A | 7’’ | 12’’ | 10’’ | 6.6 | 700 | 2 |
| Skarv B&C | 7’’ | 12’’ | 10’’ | 3.3 | 700 | 2 |
| Tilje | 5 ½’’ | 10’’ | 8’’ | 6.6 | 700 | 2 |
| Idun | 7’’ | 12’’ | 10’’ | 13.5 | 700 | 1 |

Tab. 5 Tubing and Flowline sizes and lengths (Source: Skarv Idun PDO/PIO; Ref. no 31.)

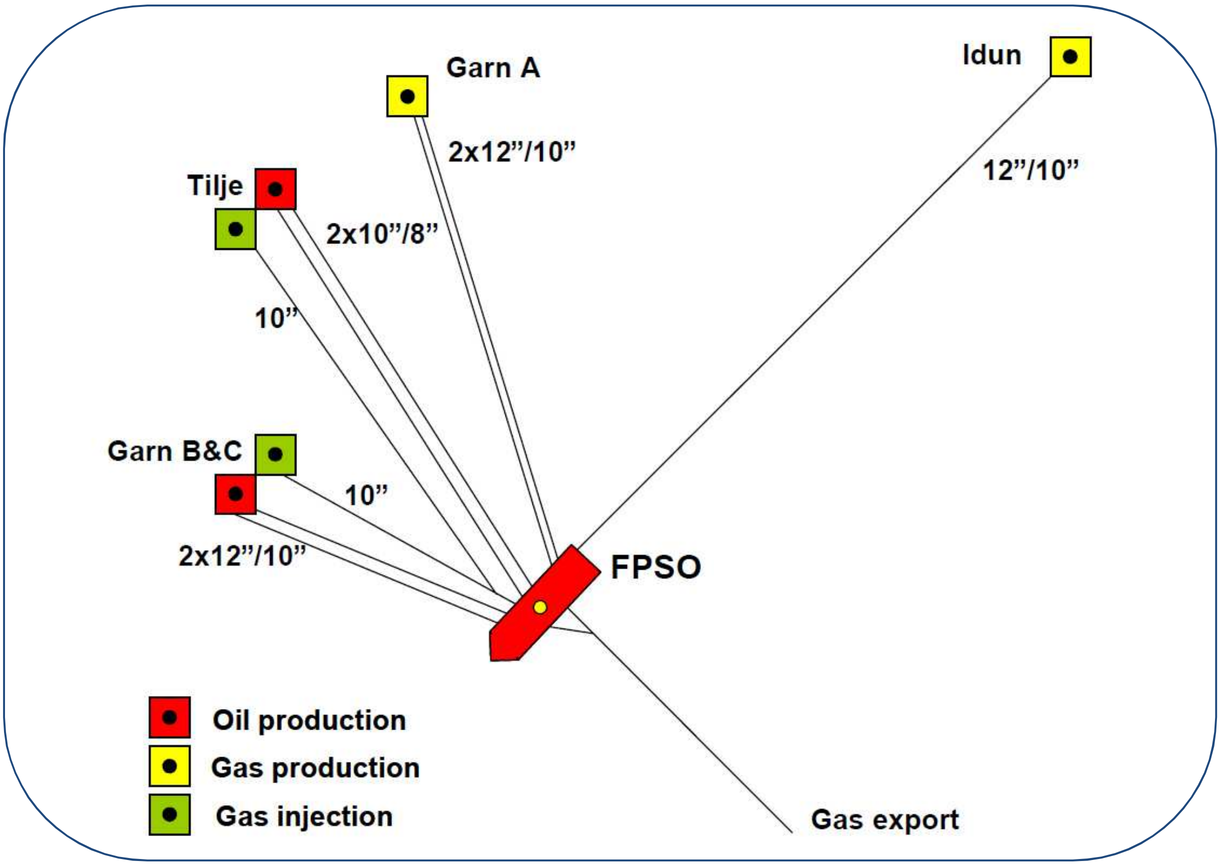


Fig. 35 Schematic Pipeline Layout used in Simulation Model
(Source: Skarv Idun PDO/PIO; Ref. no 31.)

### 3.1.9. Host

Fig. 36 Skarv FPSO
(Source: http://www.gospodarkamorska.pl/_upload/articles/1435/img/skarv.jpg

As mentioned before Skarv/Idun field is developed subsea utilizing Floating, Production, Storage and Offloading (FPSO) vessel. Skarv PFSO is the biggest that type vessel ever utilized on the Norwegian Continental Shelf. The FPSO has a length of 292 [m], breadth of 50.6 [m] and is 29 [m] deep and accommodate up to 100 people in single cabins. FPSO vessel has a production capacity of 85,000 [bbl/d] of oil and 15 [mmcm/d] gas and an 875,000 [bbl] storage capacity. The topsides weigh 18,000 [t], the hull 49,000 [t] and the turret mooring system 7000 [t].

## 3.2. Production Geology and Geophysics

Regional 3D Seismic Line showing the Skarv Field as a narrow fault terrace down-thrown from the Nordland Ridge is shown in the Figures below.

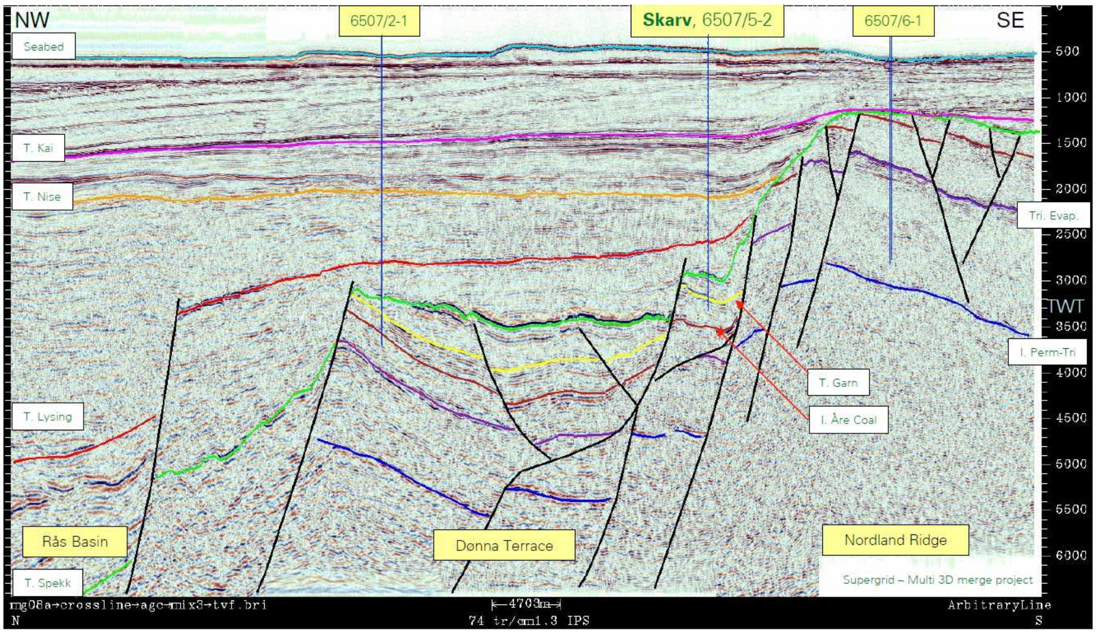


**Fig. 37 Regional Line (3D) and interpretation of structural style across the Nordland Ridge and Donna Terrace (Source: Skarv Idun PDO/PIO; Ref. no 31.)**

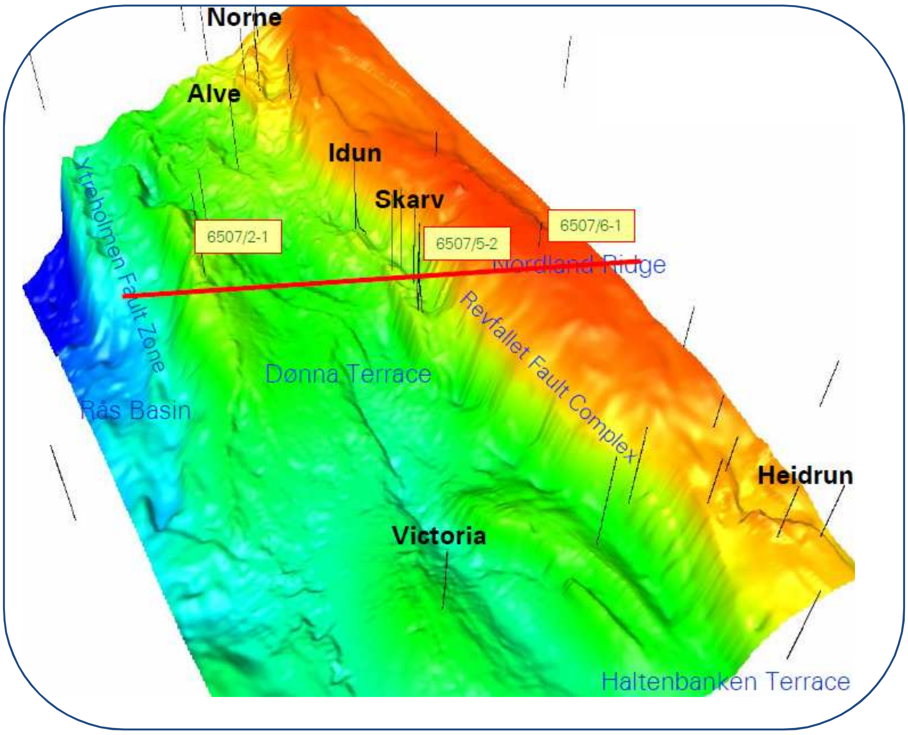


**Fig. 38 3D regional surface showing the top Garn depth, location of main structures, wells and regional line depicted in Figure 37 (Source: Skarv Idun PDO/PIO; Ref. no 31.)**

### 3.2.1. Seismic data and interpretation

All the data from the 9 appraisal wells drilled on the Skarv/Idun has been incorporated in the evaluation. The well to seismic tie is very good for the three reservoir levels. The available 3D seismic surveys in the greater Skarv Idun area have been used to support the regional understanding.

Six main horizons above the reservoir have been interpreted: Seabed, Top Kai, Top Nise, Top Lysing, Top Lange and Top Spekk. At reservoir level four horizons have been interpreted in detail: Top Garn, Top Ile, Top Tilje and Near Base Tilje, providing good constraints on reservoir isochrons. Reservoir faults are well defined on the seismic data. The Skarv tilted fault block is laterally divided into three segments, A, B and C by NW-SE cross-cutting faults. The compartments of the Garn reservoir are supported by the different fluid fills encountered in wells.

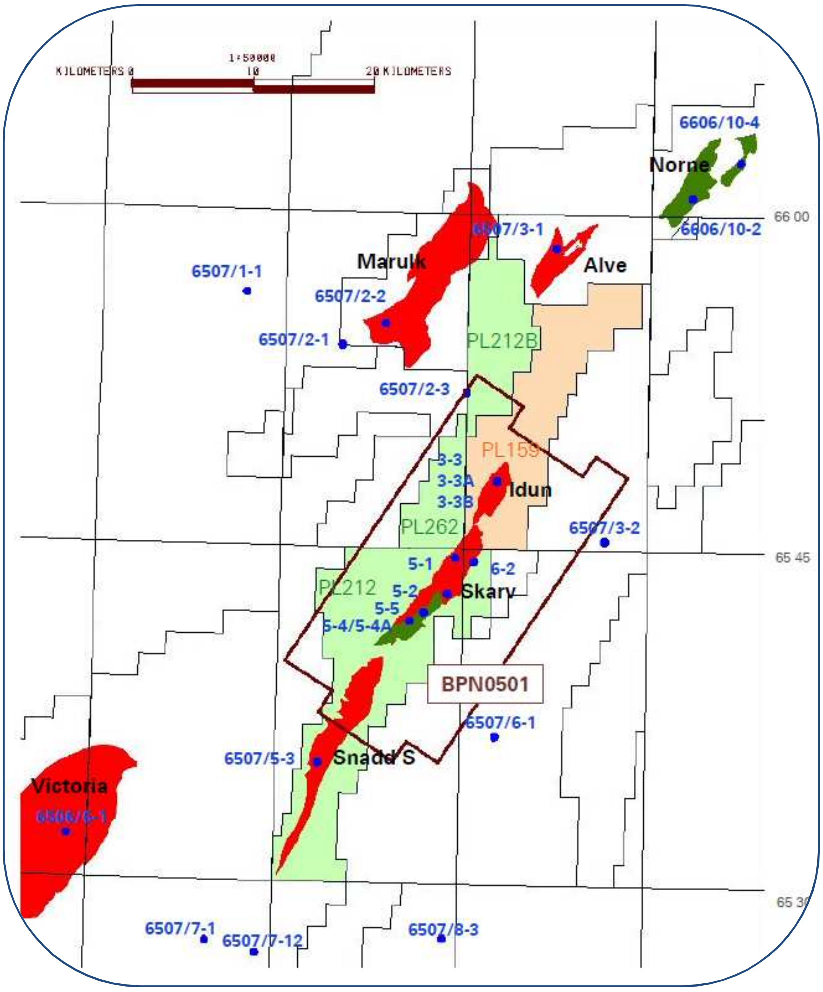


Fig. 39 Skarv/Idun seismic survey area (Source: Skarv Idun PDO/PIO; Ref. no 31.)

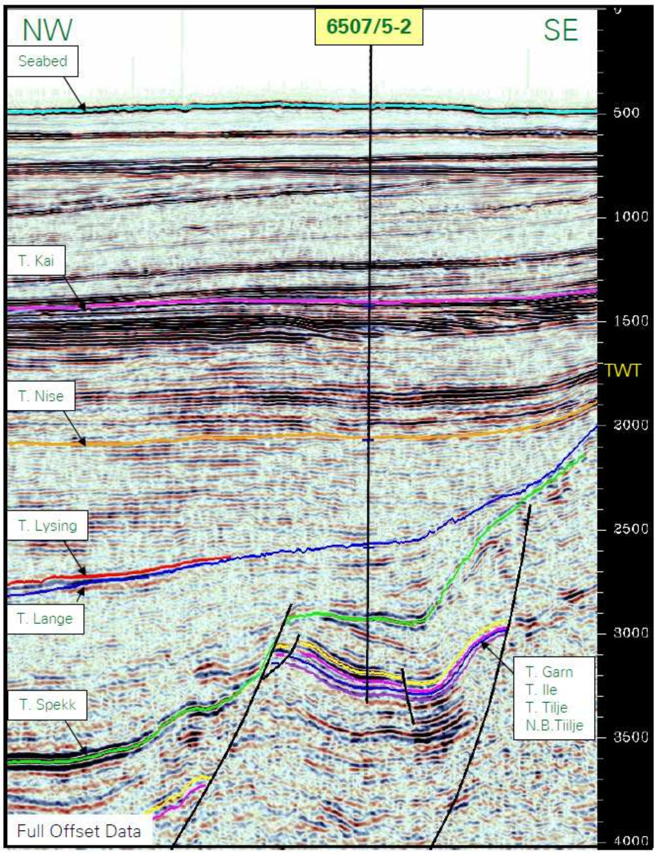


Fig. 40 Skarv appraisal well 6507/5-2 showing interpreted horizons (Source: Skarv Idun PDO/PIO; Ref. no 31.)

## 3.2.2. Stratigraphy and characteristic of the reservoir

The Garn formation is normally about 50 [m] thick and consists of sandstone interpreted as deposited in a shallow tidal marine environment. The reservoir comprises clean, stacked, typically medium grained sandstones with good to excellent reservoir properties (average porosity 18.8 [%], arithmetic mean permeability 2100 [mD]). The underlying Not formation is typically about 35 [m] thick and the better quality upper part is included with the Garn formation reservoir for development purposes although reservoir quality is significantly poorer (average porosity 14.7 [%], arithmetic mean permeability 125 [mD]). The Ile formation is normally about 30 [m] thick and consists of siltstone and sandstones interpreted to be deposited in a open shallow marine shelf. The reservoir has poor to moderate reservoir properties (average porosity 13.1 [%], arithmetic mean permeability 12.5 [mD]). The Tilje formation is normally about 100 [m] thick and consists of an alternating sandstones, siltsones and shales interpreted to be deposited in a tidal marine environment. In general the reservoir has only moderate reservoir quality (average porosity 14.9 [%], arithmetic mean permeability 42 [mD]) due to vertical variability.

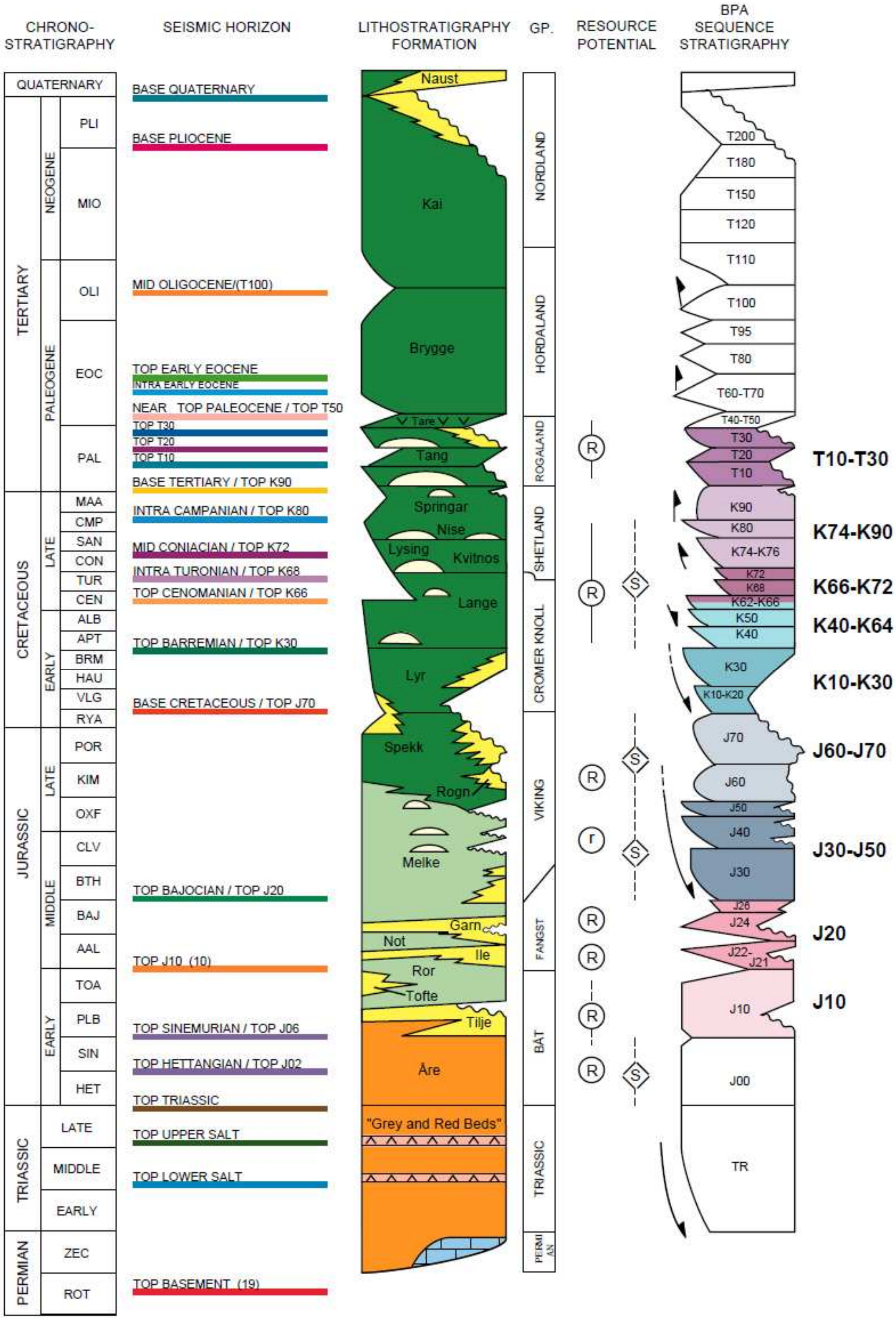


Fig. 41 Stratigraphic column of the Skarv/Idun field (Source: Skarv Idun PDO/PIO; Ref. no 31.)

### 3.2.3. Compartments and fluid contact

Volumetric uncertainty in the Skarv and Idun Fields is intensely controlled by the position of fluid contacts. Along with the 3 reservoirs, there are 5 main segments within the structure, 3 in Skarv and 2 in Idun resulting in 15 potential pressure compartments. The main source of the uncertainty in the fluid contacts is the lack of aquifer information within each of these segments and the position of the gas cap in the Skarv B segment. The positions of the fluid contacts for the Skarv and Idun fields are summarized in tables below.

| Segment | Reservoir | Type | Depth [mTVDss] |
|---|---|---|---|
| **Skarv A** | Garn | GWC | 3630 |
| | Ile | GDT | 3492 |
| | | GOC | 3588 |
| | | OWC | 3675 |
| | | WUT | 3675 |
| | Tilje | GOC | 3569 |
| | | ODT | 3629 |
| | | OWC | 3716 |
| | | OWC(max) | 3716 |
| **Skarv B** | Garn | GOC | 3584 |
| | | OUT | 3630 |
| | | ODT | 3690 |
| | | OWC | 3710 |
| | | OWC(max) | 3716 |
| | Ile | WUT | 3717 |
| | Tilje | WUT | 3811 |
| **Skarv C** | Garn | GOC | 3517 |
| | | ODT | 3669 |
| | | OWC | 3744 |
| | | OWC(max) | 3789 |
| | Ile | WUT | 3580 |
| | Tilje | WUT | 3661 |

Tab. 6 Fluid contact information for the Skarv Field (Source: Skarv Idun PDO/PIO; Ref. no 31.)

| Segment | Reservoir | Type | Depth [mTVDss] |
|---|---|---|---|
| **Idun W** | Garn | GDT | 3397 |
| | | GWC | 3672 |
| | Ile | GDT | 3447 |
| | | GWC | 3674 |
| | Tilje | GDT | 3647 |
| | | GWC | 3678 |
| **Idun E** | Garn | GDT | 3591 |
| | | GWC | 3674 |
| | Ile | GWC | 3678 |
| | Tilje | WUT | 3767 |
| | | GWC | 3682 |

Tab. 7 Fluid contact information for the Idun field (Source: Skarv Idun PDO/PIO; Ref. no 31.)

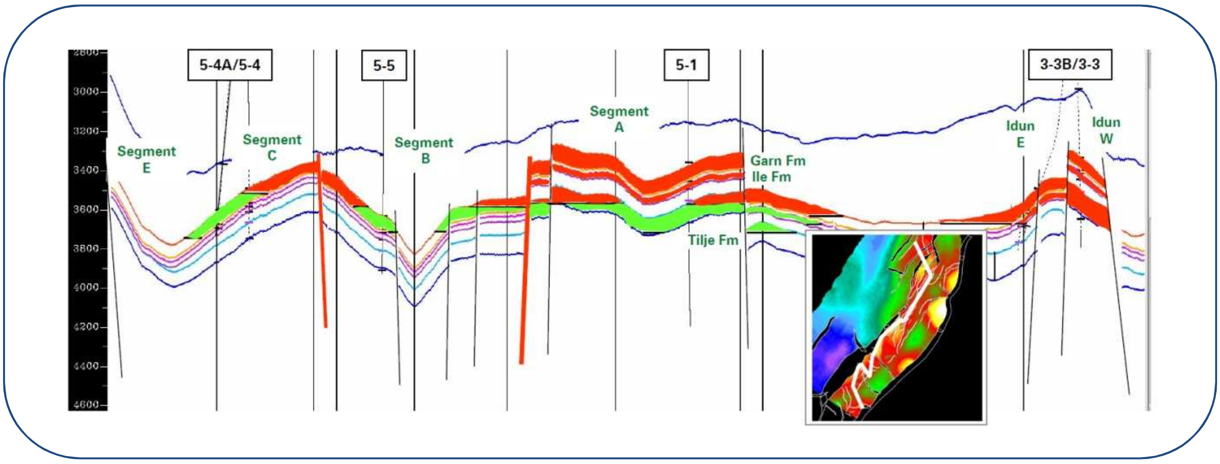


**Fig. 42 Cross-section of the Skarv and Idun Fields illustrating the position of fluid contacts (Source: Skarv Idun PDO/PIO; Ref. no 31.)**

## 3.3. Production strategy and production profiles

The production strategy assumes simultaneous oil and gas production from the Skarv and Idun fields. The oil in the Skarv Garn and the Skarv Tilje reservoirs will be produced using pressure support from gas injection. The gas reservoirs will be produced by depletion.

Due to the small in place volumes of oil expected within the Ile Formation in the A segment and the poor reservoir quality, it is not planned to drill dedicated wells to recover these. Although a thin oil rim is expected within Ile based on the PVT analyses from gas samples, no oil has been intersected by the appraisal wells. In the A segment well 6507/5-1 found gas down-to while well 6507/5-2 found water up-to. The Ile gas is planned produced commingled with Garn gas in the A segment producers. The decision to use gas injection for pressure support was made at the end of 2004 based on an evaluation involving several disciplines: reservoir, economics, facilities, drilling and HSE. All supported the selection of gas injection as the preferred pressure support method.  The main reasons were the higher oil recovery efficiency, better economics and reduced risk of barium sulphate scale (with associated negative cost and HSE implications) compared to water injection. Once gas injection is stopped, the gas injectors and oil producers will be used to back produce the gas in the Skarv Field. The oil producers will be kept on stream for as long as they continue to produce.

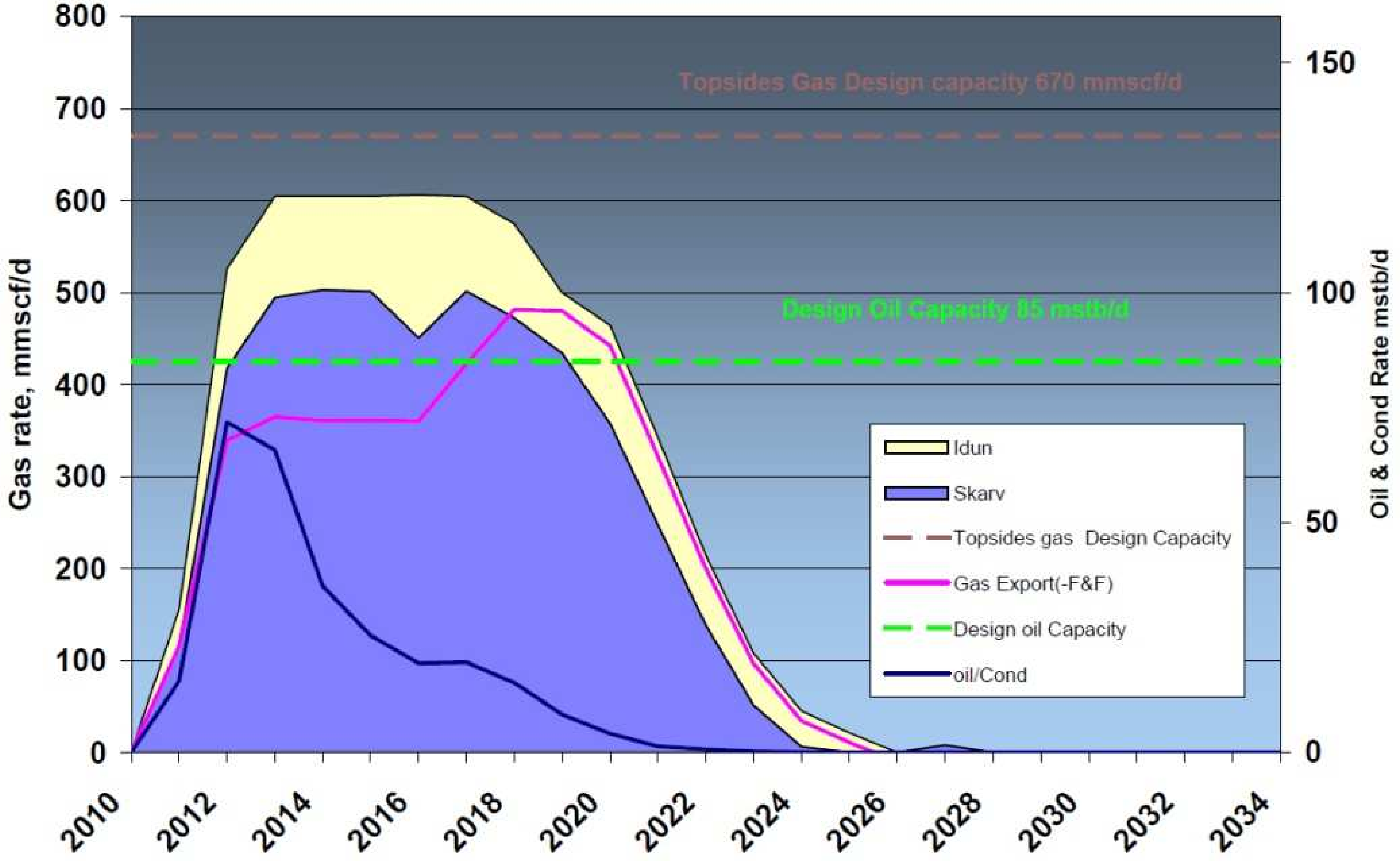


Fig. 43Technical production profile for the Skarv/Idun Development (Source: Skarv Idun PDO/PIO; Ref. no 31.)

### 3.3.1. Fluid properties and initial reservoir conditions

The fluid properties used for estimation of surface condition volumes (including associated solution gas and condensate oil volumes) and reservoir conditions are presented in tables below (Tab. 8. and Tab.9.).

| Segment | Layer | Bg $Sm^3/m^3$ | CGR mmbbl/Bcf | Bo $Sm^3/m^3$ | GOR Bcf/mmbbl |
|---|---|---|---|---|---|
| A Segment | Garn Formation | 0.00408 | 0.0352 | - | - |
| | Ile Formation | 0.00416 | 0.0594 | 1.6337 | 1.171 |
| | Tilje Formation | 0.00425 | 0.0690 | 1.7003 | 1.207 |
| B Segment | Garn Formation | 0.00413 | 0.0643 | 1.6845 | 1.210 |
| C Segment | Garn Formation | 0.00414 | 0.0638 | 1.6803 | 1.204 |

**Tab. 8 Overview of the gas PVT parameters (Gas expansion and Condensate-gas Ratios) and oil PVT parameters (Oil shrinkage and Gas-oil Ratios) used for estimation of in-place volumes for the Skarv Field. (Source: Skarv Idun PDO/PIO; Ref. no 31.)**

| Parameter | Skarv Garn A Gas | Skarv Garn Oil | Skarv Ile Gas | Skarv Tilje Oil | Idun Gas |
|---|---|---|---|---|---|
| Reservoir depth [mtvdds] | 3250-3630 | 3520-3750 | 3330-3600 | 3570-3720 | 3300-3700 |
| Reservoir Pressure [bara] | 360-372 | 370-386 | 360-370 | 370-380 | 368-374 |
| Temperature [°C] | 135-155 | 145-160 | 135-155 | 145-160 | 135-160 |
| Oil Gravity [°API] | 55 | 33.6 | 42.3 | 32.8 | 53 |
| Gas Gravity | 0.69 | 0.76 | 0.72 | 0.78 | 0.637 |
| GOR [$Sm^3/Sm^3$] | 5089 | 213 | 3323 | 224 | 25600 |
| CGR [$Sm^3/mmSm^3$] | 196.5 | - | 300.9 | 0 | 39.1 |

**Tab. 9 Reservoir Conditions and Fluid Properties (Source: Skarv Idun PDO/PIO; Ref. no 31.)**

## 3.3.2. Recoverable resources

Gas Initially in Place (GIIP) and Stock Oil Initially in Place (STOIIP) for the Skarv Field based on the model (described in the chapter 3.2.3.) including condensate and associated gas volumes are shown in the Tab.10., Tab.11. and two pie-charts below (Fig.43. and Fig.44.).

| Gas Volumetrics | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Field** | **Segment** | **Formation** | **BRV MMm$^3$** | **PV MMm$^3$** | **Average Ø %** | **HCPV MMm$^3$** | **Average Sg %** | **Free Gas bcf** | **Associated gas bcf** | **Total GIIP bcf** |
| Skarv | A | Garn | 539.8 | 98.8 | 18.3% | 87.4 | 88.4% | 756.3 | 0.0 | 756.3 |
| | | Ile | 186.5 | 26.1 | 14.0% | 15.3 | 58.5% | 129.6 | 21.5 | 151.1 |
| | | Tilje | 75.4 | 12.0 | 16.0% | 7.7 | 63.7% | 63.6 | 140.4 | 204.1 |
| | B | Garn | 100.0 | 17.7 | 17.8% | 15.8 | 89.2% | 135.3 | 61.0 | 196.3 |
| | C | Garn | 73.5 | 13.0 | 17.7% | 12.0 | 92.1% | 102.1 | 120.5 | 222.6 |
| | Total | | 975.1 | 167.7 | | 138.1 | | 1186.9 | 343.4 | 1530.3 |

Tab. 10 GIIP & STOIIP estimates for the Skarv Field. Volumes in field units and include associated gas and condensate oil. (Source: Skarv Idun PDO/PIO; Ref. no 31.)

| Oil Volumetrics | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Field** | **Segment** | **Formation** | **BRV oil MMm$^3$** | **PV MMm$^3$** | **Average Ø %** | **HCPV MMm$^3$** | **Average So %** | **Free Oil mmbbl** | **Condensate Oil mmbbl** | **Total STOIIP mmbbl** |
| Skarv | A | Garn | 0.0 | 0.0 | | 0.0 | | 0.0 | 26.6 | 26.6 |
| | | Ile | 84.1 | 10.6 | 12.6 | 4.8 | 44.9% | 18.3 | 7.7 | 26.0 |
| | | Tilje | 352.6 | 55.1 | 15.6 | 31.5 | 57.0% | 116.4 | 4.4 | 120.8 |
| | B | Garn | 105.0 | 16.8 | 16.0 | 13.5 | 80.4% | 50.4 | 8.7 | 59.1 |
| | C | Garn | 190.6 | 30.9 | 16.2 | 26.7 | 86.6% | 100.1 | 6.5 | 106.6 |
| | Total | | 732.4 | 113.4 | | 76.5 | | 285.2 | 53.9 | 339.1 |

Tab. 11 GIIP & STOIIP estimates for the Skarv Field. Volumes in field units and include associated gas and condensate oil. (Source: Skarv Idun PDO/PIO; Ref. no 31.)

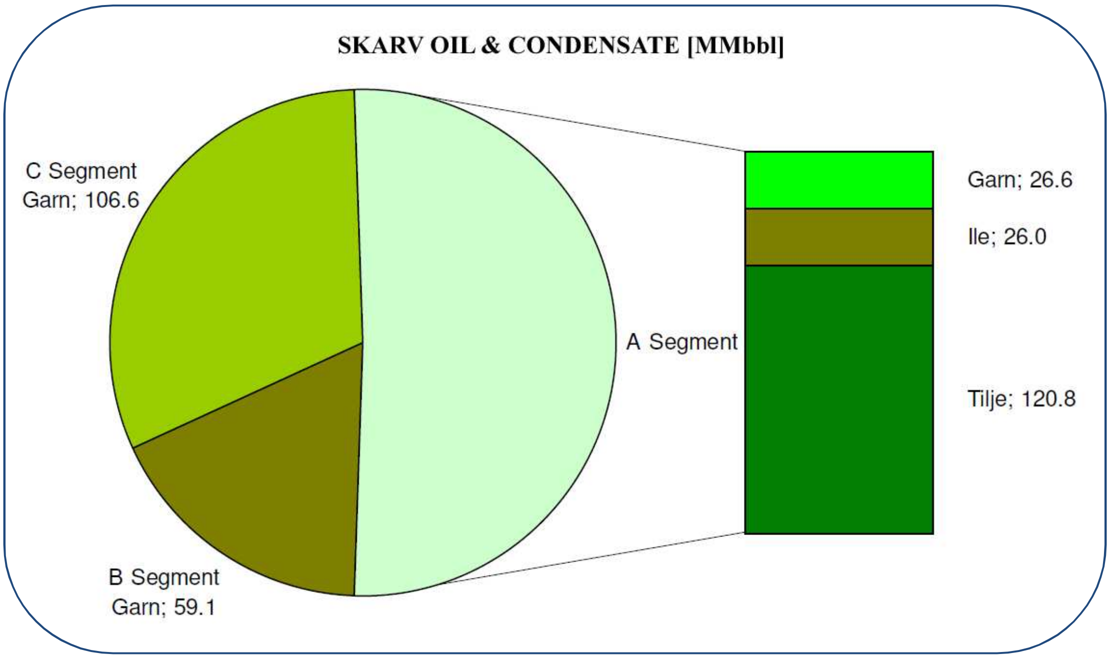


**Fig. 44 Distribution of Stock Tank Oil Initially in Place (STOIIP) within the Skarv Field (volumes are in MMbbl and include condensate oil)**
**(Source: Skarv Idun PDO/PIO; Ref. no 31.)**

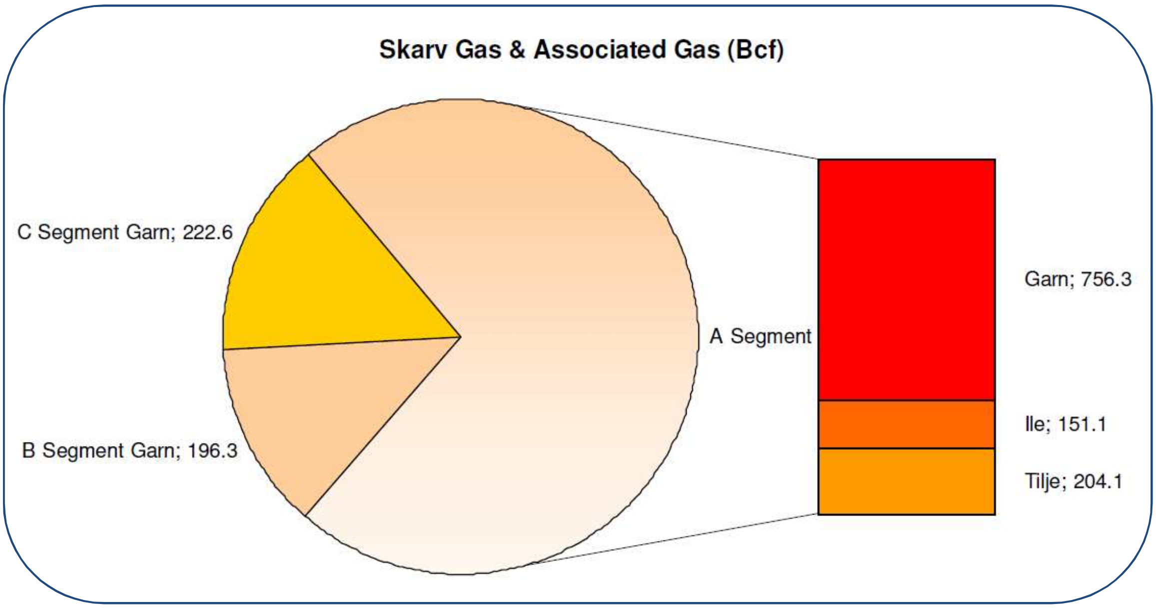


**Fig. 45 Distribution of Gas Initialy in Place (GIIP) within the Skarv Field (volumes reported in Bcf and include associated solution gas)**
**(Source: Skarv Idun PDO/PIO; Ref. no 31.)**

## 3.3.3. Reservoir simulation

**Skarv reservoir simulation model** was generated in 2006, based on the 3D seismic shot over the Skarv and Idun Fields the year before. The reservoir model covers the Skarv and Idun Fields. The Skarv Idun simulation grid dimensions are 57x228x46, with a grid size of approximately 100m x100m. The layer thickness varies but is approximately 4 m and the number of active cells is 115 000. The model has been run as a compositional model to more accurately simulate the gas injection process. Each of the main segments has its own PVT data-set and is initialized with its own fluid contacts, by importing an initial $S_w$ map from the upscaled Geo-model. Faults have been included in the model as sealing barriers, except where large pressure drops across the faults occur which could lead to fault 'breakdown' or leakage of gas. The Idun faults have therefore been left open. The subsea flowlines have been included as a pipeline network in the simulation model to model the pressure drops between the wells and the FPSO.

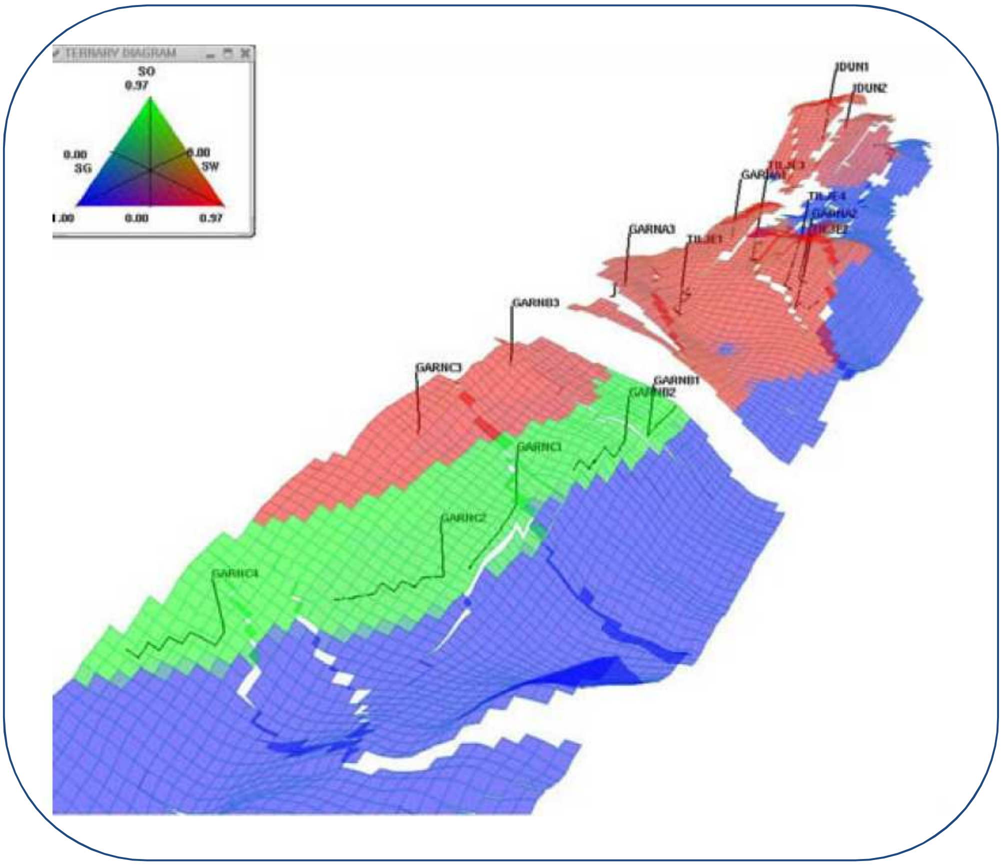


Fig. 46 Skarv Idun Reservoir Model Simulation Grid (Source: Skarv Idun PDO/PIO; Ref. no 31.)

**Idun simulation model** is an Eclipse black oil formulation based on the 3D seismic shot in 2005. The simulation grid dimensions are 69x79x29 cells, with a grid size size of 100 [m] x100 [m]. The layer thickness varies from 6 to 10 meters. The water saturation is based on initial Sw maps from the up scaled Idun Geo-model. The Idun field is regarded as one pressure regime with a common GWC and PVT parameters. The PVT input is based on EOS modelling using PVT data from the exploration well and the 4 stage process at the Skarv FPSO. The fault between the western and eastern segment is sealing, while the minor faults are open within the same formation.

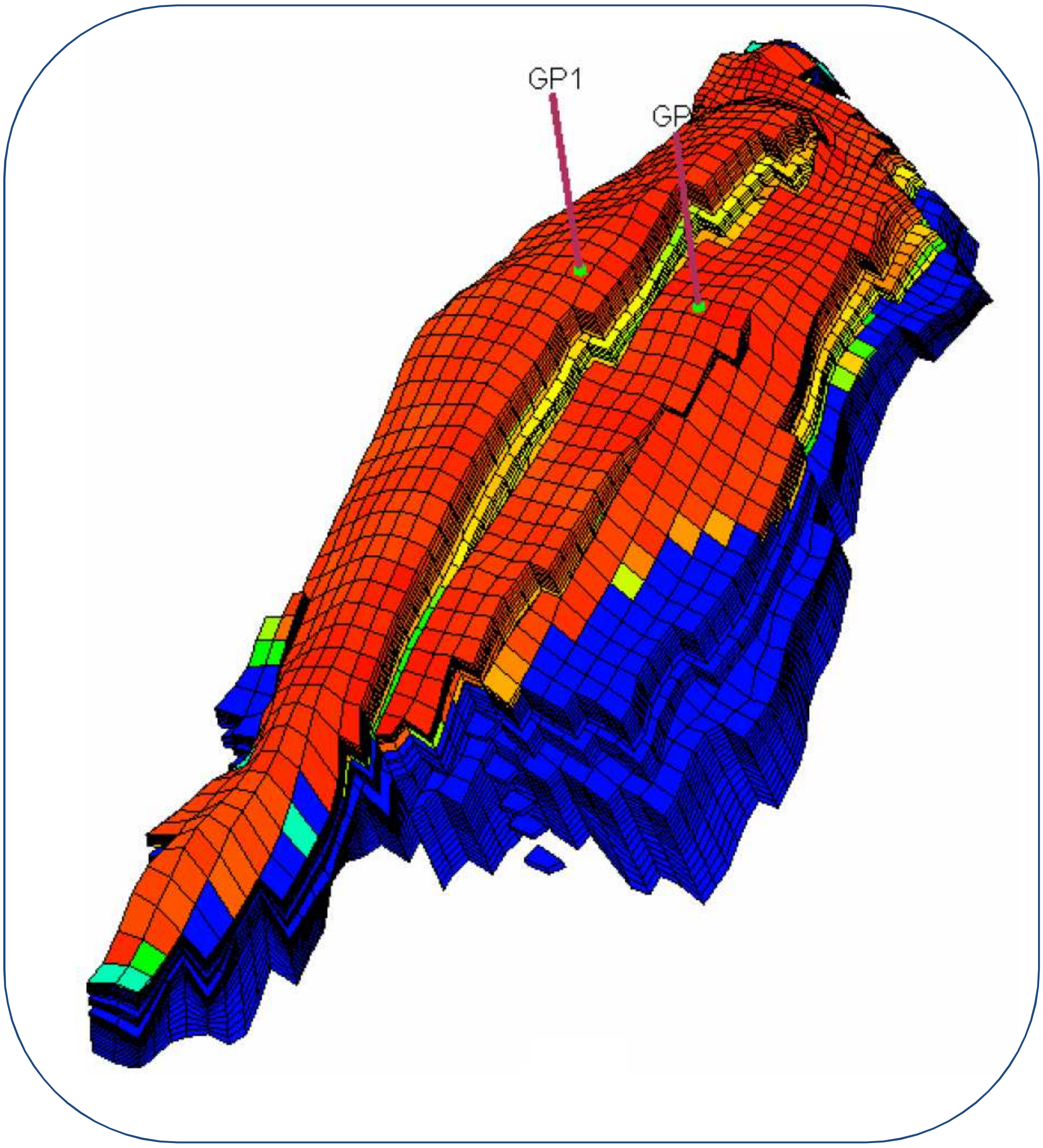


Fig. 47 Idun Simulation Model (Source: Skarv Idun PDO/PIO; Ref. no 31.)

# 4. Review of the Transocean's Polar Pioneer semi-submersible drilling rig

The Polar Pioneer is a 4th generation semi-submersible rig built in 1985 by Hitachi Zosen in Ariake (Japan). The rig is especially designed and constructed to operate in cold, harsh environments. Polar Pioneer can operate in water depths range from 70 to 500m and is equipped with 15000 psi well control equipment. The Blow-Out Preventer and the choke system is especially fitted for handling High Pressure / High Temperature (HP/HT) wells, which are relatively often on the Norwegian Continental Shelf. Polar Pioneer is classified by the Det Norske Veritas complies and to the regulations of the flag state (NMD of Norway), UK Department of Energy, UK Health and Safety Executive and international requirements of IMO-MODU Codes and SOLAS.


Fig. 48 Transocean Polar Pioneer semi-submersible drilling rig (Source: Transocean)

## 4.1. General information and technical dimensions

| Name | Description |
|---|---|
| **Unit Name** | POLAR PIONEER |
| **Unit Owner and Operator** | Transocean Offshore Inc. |
| **Flag/Port of registry** | Majuro, Marshall Island |
| **Unit classification** | Det Norske Veritas Classification A/S . Maltese Cross 1A1-Column Stabilised Unit., |
| **Additional class notifications** | Drill, HELDK, POSMOOR(ATA), CRANE, E0, ICE T. NONSELFPROPELLED |
| **Rated drilling depth** | 7,600 [m] RKB |
| **Maximum water depth** | 500 [m] |
| **Minimum operating water depth** | 70 [m] |
| **Rig design** | Polar (Sonat)/Hitachi |
| **Year of construction** | 1985 |
| **Yard** | Hitachi Zosen, Ariaki, Japan |
| **Year placed in service** | 1985 |
| **Unit shape/unit design** | 8 x columns x 2 pontoon supported semi- submersible |
| **No of thrusters** | 4 each of 2,450 [kW] |
| **Transit speed towed** | 6 [knots] |
| **Transit speed thrusters** | 6 [knots] |
| **Positioning system (anchor, DP, combined)** | Eight point anchor/chain system, automatic thruster assisted (ATA) |
| **Main deck width** | 71 [m]. Breath all over: 89 [m] |
| **Main deck length** | 85 [m]. Length all over: 122 [m] |
| **Depth keel to main deck** | 41.65 [m] |
| **Draughts, Drilling** | 23 [m] - Displacement: 46,440 [tonnes] |
| **Draught, Survival** | 19 [m] - Displacement: 43,312 [tonnes] |
| **Draught, Transit** | 9.15 [m] - Displacement: 32,554 [tonnes] |
| **Total drilling variable load, ex. anchor tension** | 3.514 [tonnes] |
| **Total survival variable load** | 3.514 [tonnes] |
| **Total transit variable load** | 3.514 [tonnes] |
| **Accommodation** | Maximum 110 people in two-men cabins |
| **Helideck designed for** | Chinook and Sikorski S61N |

Tab. 12 Transocean Polar Pioneer - general information/dimensions (Source: Transocean)

| Environmental criteria for operation | | |
|---|---|---|
| **ENVIRONMENTAL CONDITIONS** | **SURVIVAL CONDITIONS** | **LIMITING OPERATION CONDITION DRILLING** |
| **Wind speed** | 55 [m/s] 10 [min] average | 30 m/s |
| **Wave height** | $H_{max}$ 32 [m] | $H_{max}$ 13.8 [m] |
| **Mean wave period** | 11-15 [s] | 12 [s] |
| **Current speed** | 1.6 [m/s] | 0.75 [m/s] |

Tab. 13 Transocean Polar Pioneer - environmental criteria for operation (Source: Transocean)

The whole Transocean Polar Pioneer semi-submersible drilling rig, with installed equipment is showed in the figures attached at the end of this Master's Thesis:

- Polar Pioneer – Profile view: Fig. 55.
- Polar Pioneer – Front view: Fig. 56.
- Polar Pioneer – Top view: Fig.57.
- Polar Pioneer – Main deck: Fig. 58.
- Polar Pioneer – Drillfloor: Fig. 59.

## 4.2. Storage capacities and marine equipment

| Storage capacities | |
|---|---|
| **Diesel oil** | 1,795 [$m^3$] |
| **Helicopter fuel** | 10 [$m^3$] |
| **Fuel consumption, transit** | 40 [tonne/day] |
| **Fuel consumption, drilling** | 25 [tonne/day] |
| **Drilling water** | 1771 [$m^3$] |
| **Potable water** | 770 [$m^3$] |
| **Active/Reserve liquid mud (on deck)** | 202 [$m^3$] /263 [$m^3$] |
| **Reserve liquid mud ( in pontoons)** | 500 [$m^3$] |
| **Brine/low toxic oil storage** | 457 [$m^3$]/770 [$m^3$] |
| **Bulk bentonite/barite** | 560 [$m^3$] |
| **Bulk cement** | 360 [$m^3$] |
| **Sack storage** | All mud and additives supplied in 40x3 [$m^3$] cont. for auto-feeding |
| **Pipe racks area** | 2330 [tonnes] /745 [$m^2$] |
| **Riser racks** | 2430 [tonnes]/811 [$m^2$] |
| **BOP storage** | 220 [tonnes[ /25 [$m^2$] |
| **Miscellaneous storage area** | 150 [$m^2$] |

Tab. 14 Transocean Polar Pioneer - storage capacities (Source: Transocean)

| Name of the element | Description | |
|---|---|---|
| **Rig power plant** | Complete power system comprising of diesel driven generator sets supplying AC and DC power. In the drilling mode sufficient power are available to control and power simultaneously two mud pumps and top drive both at full load and the drawworks at half load with thrusters working to assist positioning unit and with one diesel engine generator as a stand-by. | |
| **Diesel engine plant** | 5 each diesel engines, in two engine rooms | |
| | Make | Bergen Diesel. |
| | Type | KVG-18, each 2750 [kW] |
| | Total output | 13,750 [kW] at 720 [rpm]. |
| | Independent fuel supply to each engine and automatic engine shut down in case of 'racing'. | |
| **AC - Generator** | One generator set, capable of taking the peak demand, with a second as a 100 [%] stand-by. | |
| | Quantity | 5 |
| | Make | NEBB |
| | Type | WAB 900 G10 HW |
| | At rotation speed of | 720 [RPM] |
| | Continuous output | 2,750 [kW] |
| | Output Voltage | 6,000 [V] |
| **Emergency generator** | One emergency generator set of 1137 [kW] complete with its own switch board and wiring. The emergency system is completely independent of the main system and powers all emergency lightning and functions. | |
| **SCR system** | Number of SCRs | 16 |
| | Make/Type | ABB |
| | Maximum power | 8,680 [kW] |
| | Output Voltage | 600 [V] |
| **Transformer system** | Quantity | 2 |
| | Make/Type | National Ind. |
| | Continuous power | 4,000 [KVA] |
| | Output Voltage | 6000, 440, 220, 230 [V] |
| | Frequency | 60 [Hz] |
| **Propulsion/thrusters** | 4 each azimuth thrusters | |
| | Type | Liaaen TNCP 105/75-280 |
| | Motors | NEBB |
| | Output | 2400 [kW] |
| **Positioning System** | Subsea Acoustic | Transponder System |
| | Type | Kongsberg K-Pos DPM 11 – Positioning Mooring System |
| | Pos. Ref. | Kongsberg Simrad HPR 309 |
| | Type | Furuno GPS/WAAS Navigator GP32 |
| **Mooring system** | 8 point spread, 45$^0$ between the anchor lines.<br>4 double Pusnes, 750cu windlasses.<br>8 Anchors, type Stevepris MK6, 15 [tones].<br>8 Anchor Chains, Type K4, 84 [mm], 737 [tones] breaking strength, 151 [kg/m], 2000 [m] each.<br>The mooring system is thruster assisted. | |
| **Safety Equipment**<br>**Firefigting Equipment**<br>**Fire and gas detection Equipment** | The unit is equipped with safety equipment according to IMO Code, and Norwegian Regulations. | |

Tab. 15 Transocean Polar Pioneer - marine equipment (Source: Transocean)

## 4.3. Drilling and subsea/well control equipment

| Name of the element | Feature | Description |
|---|---|---|
| **Derrick/mast** | Make/type | Maritime Hydraulics |
| | Height | 51,80 [m] |
| | Width of base | 12 x 12 [m] |
| | Width of top | 5,49 x 5,49 [m] |
| | Gross nominal cap. | 453 [mt] |
| | Number of lines | 12 |
| | Hookload capacity with full setback: | 409 [mt] |
| **Racking platform** | Make/type | MH996 |
| | Capacity of 6 5/8" DP | 110 [std] |
| | Capacity of 5" DP | 65 std in addition to 6 5/8" DP |
| | Capacity of 9.5" DC | 9 [stds] |
| | Pipe handling control cabins | |
| **Drawworks** | Make/type | Continental Emsco C3 |
| | Drum type | Lebus, Grooved |
| | Spinning cathead type | Cont. Emsco GB |
| | Breakout cathead type | Cont. Emsco GB |
| | Crown safety device | Crown-O-Matic & IE TBC |
| | Sandline | NA |
| | Drum diameter | 915 [mm] |
| | Max. lift cap 12 lines | 453 [mt] |
| | Max. lift cap 10 lines | 448 [mt] |
| | No. of electric motors | 3 |
| | Electric motor make | NEBB |
| | Output power | 2,230 [kW] |
| **Auxiliary brake** | Make/Model | Baylor Elmagco mod. 7820 |
| | Independent back-up system | Battery pack |
| **Kinetic Energy Monitoring system** | Make/type | Innduative Electronics |
| **Crown block** | Make/type | MH |
| | Rated capacity | 590 [mt] |
| | No of sheaves | 7 |
| | Sheave diameter | 1524 [mm] |
| | Sheave grooved for line | 38 [mm] |
| **Travelling block** | Make/type | MH |
| | Rated capacity | 590 [mt] |
| | No of sheaves | 6 |
| | Sheave diameter | 1524 [mm] |
| **Drill string motion compensator (Crown Mounted)** | Make | Maritime Hydraulics |
| | Type | CBC 270-25 |
| | Stroke in m | 7,6 [m] |
| | Capacity - compensated | 269 [mt] |
| | Capacity - locked | 453 [mt] |

| Name of the element | Feature | Description |
|---|---|---|
| **Active heave compensator** | Make | Mercur/Maritime Hydraulics |
| | Type | Hydraulic |
| | Stroke | 7,6 [m] |
| | Capacity | max hydraulic force +- 15 [mt] |
| **Rotary table** | Make/type | Cont. Emsco T4950-65 Maximum |
| | Opening | 1257,3 (49 1/2”) |
| | Rated capacity in [mt] | 590 |
| | Driven by an independent electric motor, two speed gearbox | |
| **Master Bushings (split type)** | Make/Type | Varco MPCH |
| | Full range of inserts bowls to suit all contractor's tubulars and for running all standard casing sizes. | |
| **Drillpipe rack to drillfloor handling system** | MHI/Miko Pipe Handling System; overhead cranes bringing tubulars into remote operated skid way, which delivers piping to the drill floor. Satisfies latest NPD requirement. | |
| **Top drive** | Make/Type | Maritime Hydraulics / DDM 650-HY |
| | Rated capacity | 590 [mt] |
| | Working pressure in bar | 350 (5000 [psi]) |
| | Remote operated kelly cock | 1 ea |
| | Hydraulic Driven by motor | 4 ea ( 4 x 500 [ccm]) |
| | Make | Rexroth (MH) |
| | Output torque in Nm | 54012 @ 132 [rpm] |
| | Gearbox, no of gears | 3 |
| | Maximum rotary speed, RPM | 206 @ 33488 [Nm] |
| | Mudline diameter in inch | 3 |
| **Drill pipe** | Rig is capable of handling tubulars in range from 3 ½” to 6 5/8” | |
| **Hevi-wate drill pipe** | 5 ½" OD, 5 ½ FH connections<br>5" x 50 lbs/ft, NC 50 connections | |
| **Drill collars** | Rig is equipped with:<br>9 1/2" OD, 2 13/16" ID, 7 5/8" Reg Connections,. Spiraled<br>8-1/4" OD, 2 13/16" ID, 6 5/8" Reg Connections, Spiraled,<br>6 1/2" OD, 2 13/16" ID, NC50 Connections, Spiraled | |
| **Cross-over subs** | Enough cross-over subs to make up all drill and fishing string configurations of contractor's equipment. | |
| **Handling tools** | Elevators and slips to handle all Contractor's tubulars, and casing elevators and casing slips to handle standard casing strings.<br>Manual tongs to handle all Contractor's tubulars and standard casing strings. | |
| **Iron roughneck** | Make | Maritime Hydraulics |
| | Type | 1898 |
| | Range size 3-1/2" thru 9-1/2" Remote controlled | |
| **Diverter BOP** | Make | Reagan Offshore International |
| | Model | KFDS |
| | KFDS | 10" x 24" |
| | WP | 35 [bar] |
| | OD outlets | 49-1/2" top & bottom of housing |
| | Insert packer size inch | 12" |
| | Diverter flowlines | 2 each |
| | OD of flowlines inch | 19 |

| Name of the element | Feature | Description |
|---|---|---|
| **BOP stack** | One Hydril 18 3/4" BOP stack, Working Pressure 103400 [kPa] (15,000 [psi]).<br>Rated for $H_2S$ service containing; Well head Connector, Vetco H4<br>- Two double "Hydril-Dual Cam" rams containing: Four ram type preventers with MPL ram locks, of which three preventers for drill pipe and one with single-piece shearing blind rams<br>- Acoustic control System<br>- 1060 [liters] subsea accumulators | |
| **Pipe rams available** | Rams available to dress BOP with shear/blind ram and variable rams<br>to suit ranges from 3 ½” to 7 5/8” OD Rams dressed for Sour service | |
| **Lower Marine Riser Package** | (From bottom to top:)<br>Hydraulic connector, Make Camerson Mod 70, Size 18-3/4",<br>WP kPa 68900 (10,000 [psi])<br>Bag type preventer, Make Hydril, Type "GX", Size inch 18-3/4",<br>WP kPa 68900 (10,000 [psi])<br>Flex joint, Make Oil State, Type Flex Joint Assy 18-3/4" | |
| **Choke and kill valves** | 8 each, CIW DF, 3-1/16"<br>WP kPa 103,400 (15,000 [psi]) | |
| **BOP stack handling system** | The BOP is moved by skidding arrangement from storage area to moonpool<br>and under the rotary table.<br>Overhead crane of 220 mt above storage for handling BOP & LMRP.<br>The system is fitted with a mechanical stabilising device, permitting running<br>the BOP in 1.50 of roll and pitch. | |
| **Marine riser** | Rig is equipped with marine riser for 450 [m] water depth | |
| | Make | Hughes Offshore |
| | 21" OD x 20"ID<br>3 ½" ID Kill and Choke lines, WP 15,000 [psi],<br>4" ID Booster line, WP 3000 [psi] | |
| **Telescopic joint** | 2 ea Hughes Offshore HMF, telescoping joint , double seals, support<br>ring for tensioning lines and 3" bore kill and choke hoses,<br>and booster line with WP corresponding to BOP.<br>Hydraulic locking of inner barrel. | |
| **Buoyancy modules** | Make | Eccofloat Type RG 24 |
| | Quantity | Elements for 15 joints |
| **BOP control System** | Valcon Hydraulic control system with pilot controlled subsea valves<br>electric/pneumatic powerpack, 40 x 15 [gal] bottles, total capacity 2835 [liters]<br>surface accumulators, 2 remote control stations and complete emergency<br>electric and pneumatic power back-up of all control functions | |
| **Choke manifold** | WOM choke manifold, rated to 15,000 [psi], with two Cameron remote operated chokes and 1 Cameron manually operate choke. The choke manifold is rated for $H_2S$ service. | |

| Name of the element | Feature | Description |
|---|---|---|
| **Riser tensioners** | One marine riser tensioning system of 8 eight tensioners c/w control panel, air receivers, sheaves and wireline to give a total stroke of 15,25 [m].<br>The system is independent, having its own electrically powered compressors and chemical or refrigeration air drying unit.<br>8 each, make Wichman, Capacity each, 45 [mt] (100 [kips]).<br>Maximum cylinder stroke, 3.81 [m]. Total wireline travel 15,2 [m]<br>Wireline size inch, 1-3/4. | |
| **Guideline and Podline system** | Guideline tensioning system complete with control panel,<br>air receivers, sheaves and 3/4" wirelines to give a total of 12 [m] line travel, having a capacity of 6.8 [ton] each with line storage drums behind tensioners.<br>4 + 2 each, make Wichman, Capacity each kN 71 (16 [kips]) | |
| **Mud pumps** | 3 each mud pumps of 5000 psi WP Cont. Emsco FB1600 7"x12" with 2 x DC motors. Each pump rated to 1472 [kW] continuous service. The mud pumps are fed by 3 each supercharge pumps, each of 30 [kW]. | |
| **Mud storage capacity** | 2 each active mud tanks, each of 80 [$m^3$], total 160 [$m^3$] on deck.<br>4 each reserve mud tanks total of 226 [$m^3$] on deck.<br>2 each mud storage tanks, total of 430 [$m^3$] in column.<br>1 each base oil tanks of 770 [$m^3$] in pontoon.<br>2 each brine tanks, total of 750 [$m^3$] in pontoon. | |
| **Mud mixing system** | STEP Offshore Mud Mixing System<br>3 each mud mixing pumps, 75 [kW] each.<br>2 each sack mixing stations with a total of 3 hoppers.<br>The hoppers are served by 3 surge tanks, two of 23 [$m^3$] and one of 14 [$m^2$] capacity. | |
| **Mud treatment system** | 5 each Thule VMS 100 Shale Shakers, total flowrate 4.5 [$m^3$/min].<br>16 cone Demco desilter system, fed by 75 [kW] supply pump.<br>Cap. each 1,400 [gpm].<br>1 each Brandt degasser, Cap. 3785 [$m^3$/h].<br>1 each Swaco mud/gas separator an 8" nom diam vent line to top of derrick.<br>2 each mud centrifuges. | |
| **Cementing system** | Twin Halliburton Electric powered cementing unit<br>for 1035 [bar] (15,000 [psi]) service.<br>Twin batch tanks 12 [$m^3$] each. Recalculation Averaging Mixer with capacity of 1,27 [$m^3$/min] (8 [BPM]) depending on slurry density. | |
| **Oil Based Mud arrangement** | 2 each removable Conveyor Screws are installed for transportation of cuttings from shaker into containment tanks. Space available<br>on deck for installation of 3d party Cutting Containment System | |

Tab. 16 Transocean Polar Pioneer - drilling equipment (Source: Transocean)

# 5. Application of Managed Pressure Drilling on the Skarv/Idun field

This feasibility study of using MPD technology is driven by the drilling risks encountered from the exploration and appraisal wells drilled up to date on the Skarv/Idun area (mainly **risks** of **shallow gas presence, drilling fluid losses, under-pressured and/or over-pressured layers**). Initial screening of seismic data and data from wells already drilled showed that several hazards can be expected in the Skarv/Idun area, which may have negative influence on the drilling process. There are:

1) Iceberg plough marks at the seabed (typically 20-200 [m], up to 20 [m] deep and several kilometers length);
2) Boulders in the shallow section (were reported in wells 6507/5-2, 6507/5-3, 6507/5-4 and 6507/5-1, which had to be re-spudded three times due to boulders);
3) **Over-pressured and under-pressured layers:**
    - In the well 6507/5-1 over-pressured shales at about 2100 [m] MSL.
4) **Drilling fluid losses** were encountered in the well 6507/5-4 in the 17 ½'' hole section at the depth of 1623 [m] MSL. Losses were at the level of 10 [$m^3$/hr] of drilling fluid.
5) **Wellbore instability in overburden in high inclination wells** (like in Skarv B two horizontal oil producers and Skarv C three horizontal oil producers);
6) **Swelling clays at Brygge/Tare/Tang interval;**
7) **Differential sticking while coring and drilling in the reservoir with high overbalance;**
8) **Shallow gas in the Naust Formation and at the top of the Kai Formation:**

    Horizon consistent amplitude extractions from the seismic data around Skarv show numerous well developed shallow gas anomalies. These are particularly prevalent at the top of the Kai Formation and at various levels within the Naust Formation. Some of these anomalies are very clearly indicative of shallow gas; others are more subtle but data from wells that have penetrated them show that they contain at least low concentrations of shallow gas that have been seen as bubbles emanating from the wells at the seabed (6507/5-1 and 6507/3-3).

    - **Idun** template sits within an area of abundant small shallow gas anomalies within the upper part of the Naust S-W formation. They are structurally and stratigraphically similar to the nearby anomaly that is believed to have generated bubbles that caused the 6507/3-3 pilot hole to be killed. They are contained in beds that dip to the North West and, in the event of any connectivity between anomalies, could have significant relief and associated potential for overpressure. Template location sits on the north-western edge of a shallow gas anomaly that lies at a similar depth and has a similar form to the one that gave a 3.2 [%] formation gas peak in the 6705/5-2 well. This anomaly occurs at about 1120 [m] MSL and occupies most of the quadrant to the southeast of the proposed template. Unless surface casing is set above this level, any shallow gas associated with the anomaly might prove an impediment to the drilling of wells deviated to the southeast from the template. There are also some anomalies as close to the planned location as 100 [m] at about 700 [mTVDss] and 75 [m] at 1120 [mTVDss], that have moderate to high potential for containing shallow gas.

- **Skarv A and Skarv Tilje** templates are located in the vicinity of a small shallow gas anomaly within the upper part of the Naust S-W formation. The anomaly sits at about 737-740 [mTVDss] and is therefore of particular concern because it sits above the expected depth of pressure containment in current well designs. The anomalies are structurally and stratigraphically similar to the one that is believed to have generated the gas bubbles that caused the 6507/3-3 pilot hole to be killed. The proposed Skarv A and Skarv Tilje template locations sit over the north-western margin of an extensive shallow gas anomaly in the lower part of the Naust S-W formation that continues for several kilometers to the south and east. The templates are located at a relatively low amplitude part of the area covered by the extensive anomaly that correlates with a 3.2 [%] formation gas peak in the 6705/5-2 well at a depth of 1160 [mTVDss]. Unless surface casing is set above this level, any shallow gas associated with the anomaly might prove an impediment to the deviated drilling from these templates in the direction of these anomalies. There is therefore considered to be a moderate risk for encountering shallow gas at the depth of this anomaly (about 1130 [mTVDss]).
- **Skarv B/C** drilling site with two templates, a template to the West and a template to the East, sits on the lower flank of a large scale topographic high and just above a topographic low, probably created by ice stream erosion. The 3D SO data suggest that the proposed two templates at the Skarv 'BC' drilling site sit close to the up-dip end of a shallow gas anomaly at about 774

[mTVDss] within the Naust S-W formation. This anomaly is structurally and stratigraphically similar to the anomaly that is believed to have generated the gas bubbles that caused the 6507/3-3 pilot hole to be killed.

## 5.1. Managed Pressure Drilling candidate selection

Candidate selection for MPD operation can be defined as a **process that understands the purpose of the project, procures the required data** and **investigates the data** by performing hydraulic analysis, identifies MPD variant suitable for the conditions, imply methods to achieve it, determines the viability of such methods or their alternatives, looks at the required equipment, its availability and the procedures involved in executing MPD[32].

The operator of the project should consider three key aspects of the Managed Pressure Drilling candidate selection during decision making process:

- Identify the possible serious, related to drilling problems and objectives for a given prospect, to understands the effect of those problems and objectives, and to determine the possible loss of time and money, while conventional drilling method is used;
- Study and understands different Managed Pressure Drilling variations and possible utility of MPD to mitigate drilling risks, which were identified in the first step;
- Determine additional cost associated with MPD equipment, training, developing drilling and tripping procedures, availability of necessary MPD equipment associated with safe execution of MPD operations on the proposed project;

According to the Sagan Nauduri (2009) a few important should are required for the MPD candidate selection process:

1) Defining/Identifying/Establishing the purpose:
    - Define the objectives;
    - Identify the drivers for the project;
2) Procuring information/understanding:
    - Procuring information - offset well data, geological data, equipment and design data;
    - Understanding the prospect and the drilling problems;
    - Understanding the MPD variations and select the most suitable;

3) Evaluation/analysis:
    - Conventional hydraulics;
    - MPD hydraulics;
    - Determining of critical parameters;
    - Result and decision making;

To determine whether Managed Pressure Drilling is required or not for the Skarv/Idun field conditions it should to be ensured that no other option is possible. The flow diagram showed in the figure below (Fig. 49) presents steps required to be taken by decision makers to define the feasibility of using Managed Pressure Drilling on the Skarv/Idun field (MPD solution is provided by the "red path").

There are three possible outcomes of this analysis:

1) MPD is not required:
    - Not all wells considered require MPD;
    - Changing rheology of the drilling mud or other design parameters is sufficient to overcome all drilling/production related problems;
2) MPD is not useful:
    - Given well is a potential candidate for the MPD;
    - But, MPD is not a solution;
3) MPD is applicable:
    - Given well is a potential candidate for the MPD;
    - There is a MPD variation available to suit the given scenario;

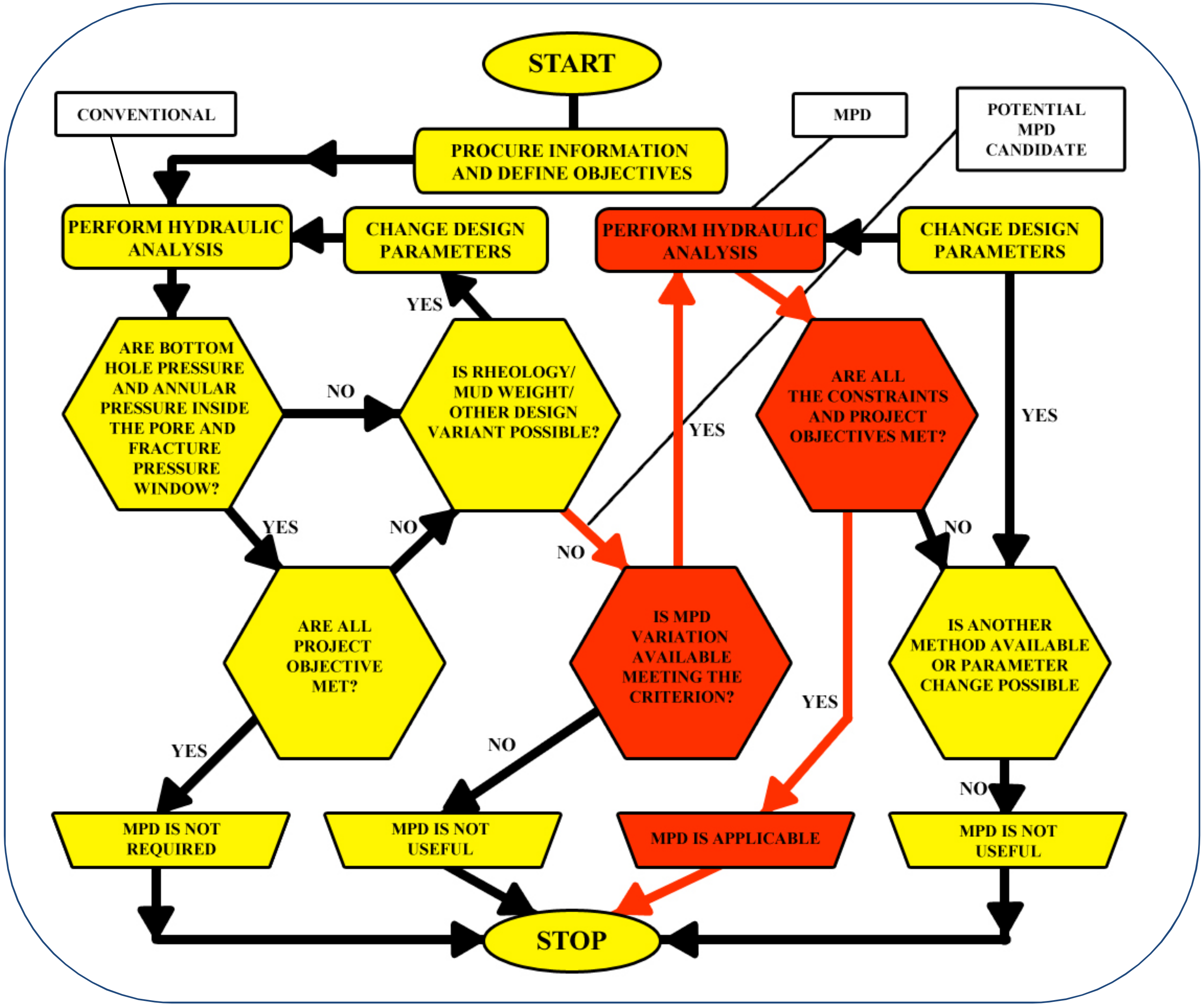


Fig. 49 MPD candidate selection Flow Diagram (Source: SPE 130330; Ref. no 17.)

After Nauduri's candidate selection process for an MPD operation is shown below (selection whether MPD is required, applicable or not useful for the Skarv/Idun conditions is performed according to the MPD candidate selection Flow Diagram from the Fig.49.):

1. Purpose of the project:
   1.1. Objectives for the project
      a. To mitigate risks caused by over-pressured layers;
      b. To minimize risks of drilling fluid losses (according to the PDO for the Skarv/Idun (marked as a low risk);
      c. To avoid wellbore instability in overburden in high inclination sections;
      d. To avoid differential sticking while coring and drilling in the reservoir with high overbalance (marked as a low to intermediate risk);
      e. To mitigate risks of shallow gas presence (marked as a low to intermediate risk);
   1.2. Drivers for the project:
      a. To minimize overbalance and therefore:
         a1. Increase Rate of Penetration;
         a2. Avoid differential sticking;
         a3. Prevent loss returns;
      b. To faster kick detection because of better flow measurements;
      c. To enable dynamic well control methods;
      d. To deal in safe manner with shallow drilling hazards such as presence of shallow gas;
2. Procuring information and understanding:
   2.1. Information about the Skarv/Idun field is provided in the Chapter 3.
   2.2. Information about the Transocean Polar Pioneer semi-submersible drilling rig is provided in the Chapter 4.
   2.3. As a case well have been chosen a well 6507/5-6 S, which is planned to be drilled from the Skarv A template (information about the well and conventional drilling procedure in the Chapter 6).

2.4. Expected drilling problems for a well 6507/5-6 S are:

a. Shallow gas in the Naust Formation and at the top of the Kai Formation;

b. Differential sticking while coring and drilling in the reservoir with high overbalance;

c. Swelling clays at Brygge/Tare/Tang interval;

d. Boulders in the shallow section;

e. Drilling fluid losses;

2.5. To overcome drilling related challenges mentioned above (most of them) the most suitable MPD variation is **Constant Bottom-Hole Pressure** (CBHP) MPD, which maintains value of the Bottom-Hole Pressure at the constant level and therefore minimizing overbalance. Despite of the not very narrow pressure window, CBHP MPD variation by proving a state of only slight overbalance may be able to mitigate the risk of the differential sticking, prevent loss returns and increase ROP. Due to applying a closed, pressurizable mud return system and special well control procedures HSE issues will be improved.

3. Evaluation and analysis:

3.1. Conventional hydraulics on the Skarv/Idun is performing according to the conventional drilling philosophy for the well 6507/5-6 S presented in the Chapter 6.1.

3.2. MPD hydraulics – due to possibility to overcome most of the drilling-related challenges in conventional way and relatively low drilling risks performing CBHP MPD hydraulics is not necessary.

3.3. Decision about not using MPD technology (CBHP variation) on the Skarv/Idun is based on the possibility for overcome drilling related challenges in more cost effective way by using conventional drilling technique. Decision is explained in the Chapter 7 and additional recommendations are also stated.

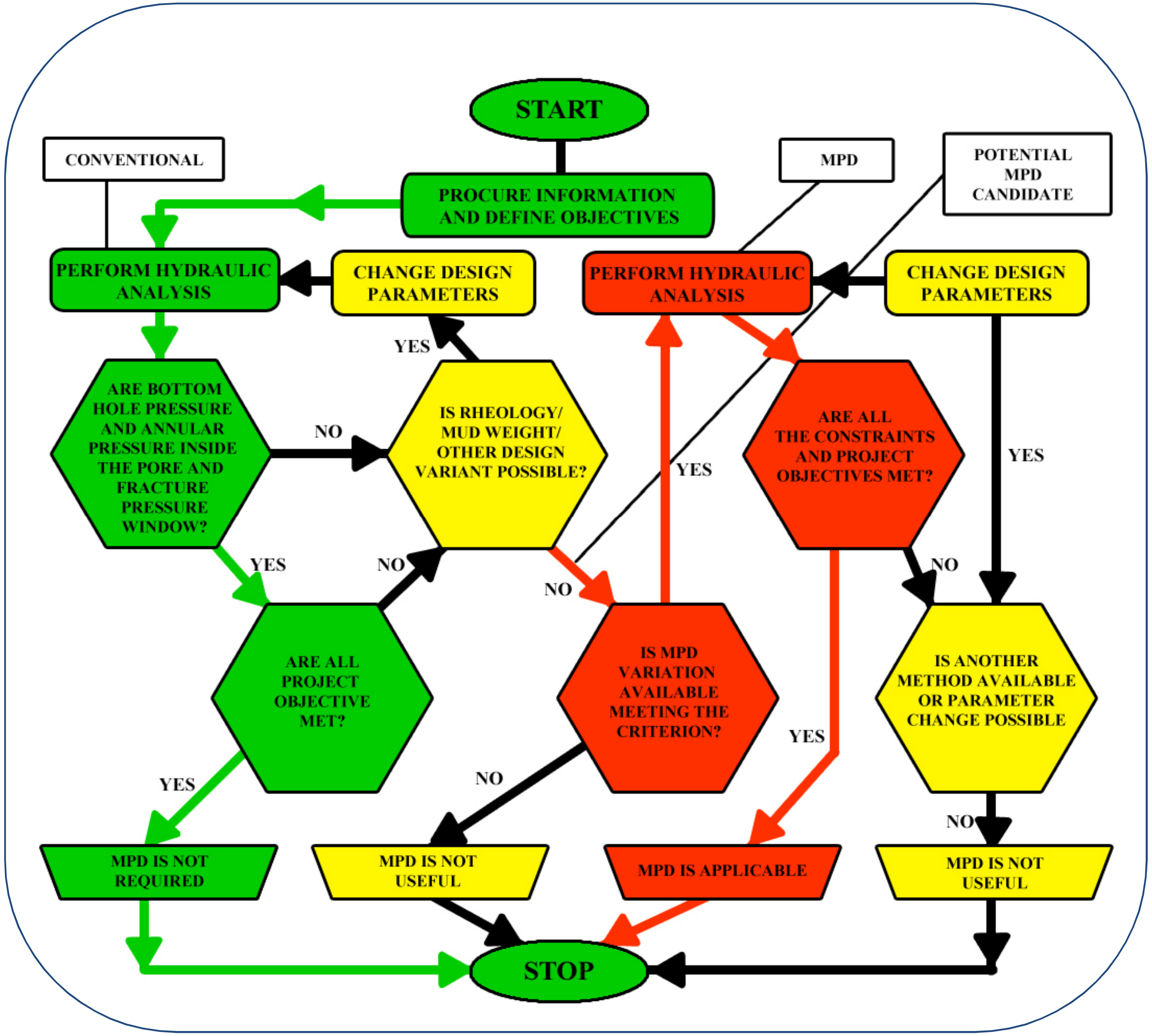


Fig. 50 MPD candidate selection Flow Diagram for the Skarv/Idun conditions

## 5.1.1. Hydraulic analysis

Hydraulic analysis is done to determine the frictional pressure drops, the changes in the equivalent circulating density, and the required mud weight to drill the given interval. The results determine whether MPD can be used to stay within the pressure limits and meet the drilling objectives of the project. Computer models and software are available in the industry to perform the hydraulic calculations and analysis. Software incorporating the temperature and the mud compressibility effects give more accurate results.

The preliminary hydraulic analysis typically consumes a lot of time. Most of these simulations are based on many unknown parameters and assumptions. Initially, the operation ranges of the different parameters, like BHP, annular pressure, ECD, and surface pressure, are determined for different mud properties, back pressures, and depths. These results are compared to the available window of operation and constraints. Based on this information, the mud-supplying companies can be approached. A mud that meets the project's requirements is chosen. The properties of the selected mud are then fine-tuned to obtain the most beneficial scenario of operation.

According to the Skarv/Idun drilling philosophy for the well 6507/5-6 S (Chapter 6.1.) to drill **36'' hole** for the 30'' and the **24'' hole** for the 18.7'' casing as a **d**rilling mud will be used **seawater and bentonite sweeps for hole cleaning** and **weighted bentonite mud in the hole when running casing. 17 1/2'' hole** for the 13 5/8'' casing will be drilled with **Carbo-Sea Oil Base Mud.** The mud in the **12 1/4 " section** will be also **Carbo-sea Oil Based Mud.**

Due to possibility to overcome drilling challenges in conventional way, there is no necessity for performing a detailed CBHP MPD hydraulic analysis. Nevertheless, It should be mentioned that there is a significant difference between in wellbore hydraulics, while drilling in conventional way and with CBHP MPD.

In conventional drilling, Bottom-Hole Pressure is the sum of the mud's hydrostatic pressure, the pressure required to overcome the annular friction, and the weight of the cuttings. This represents the equation: $BHP_{conv} = MW_{conv} + FRICTION_{conv} + CUTTINGS_{conv}$. While conditions are static, then $FRICTION_{conv}$ and $CUTTINGS_{conv}$ components of that equation are both usually zero. Therefore, the above equation becomes **$BHP_{conv} = MW_{conv}$ in the static conditions,** while the above equation is unchanged for the dynamic condition.

Therefore, "$FRICTION_{conv}$ + $CUTTINGS_{conv}$" component exerts additional pressure in the conventional dynamic condition, resulting in additional overbalance. $MW_{conv}$ component remains unchanged in both static and dynamic conditions.

While using CBHP MPD variation, Bottom-Hole Pressure value is lowered or controlled by carefully managing the mud rheology, mud weight, solids content of the mud, applied back-pressure and cuttings concentration in the annulus. The BHP is represented by the following equation: $BHP_{cbhp} = MW_{cbhp} + BP_{cbhp} + FRICTION_{cbhp} + CUTTINGS_{cbhp}$

As mentioned before, the "$FRICTION_{cbhp}$ + $CUTTINGS_{cbhp}$" component is equal to zero under static conditions, lowering the Bottom-Hole Pressure by that value compared to dynamic Bottom-Hole Pressure. To control the static Bottom-Hole Pressure or bring it very close to the dynamic Bottom-Hole Pressure, backpressure ($BP_{cbhp}$) is applied in the static condition such that: $BP_{cbhp} \approx FRICTION_{cbhp} + CUTTINGS_{cbhp}$.

Typically $BP_{cbhp}$ component is zero or has a very small value under dynamic conditions. **Therefore $BHP_{sbhp\text{-}static} = MW_{sbhp} + BP_{cbhp\text{-}static}$**

**$BHP_{cbhp\text{-}dynamic} = MW_{cbhp} + FRICTION_{cbhp\text{-}static} + CUTTINGS_{cbhp\text{-}dynamic}$**

Maintaining the static and dynamic Bottom-Hole Pressure very close to each other enables the driller to either move the Bottom-Hole Pressure close to the pore pressure or away from the pore pressure to suit the requirement. Typically, staying close to pore pressure provides greater benefits rather than staying away from it, unless the wellbore collapse limit is higher that the pore pressure. In such a case, the Bottom-Hole Pressure is maintained slightly above the wellbore collapse gradient. To maintain Bottom-Hole Pressure closer to pore pressure and reduce the overbalance, the "$MW_{cbhp}$" is reduced to a value lower that the "$MW_{conv}$". The mud circulation rate, rheology and other parameters are designed in such a way that dynamic Bottom-Hole Pressure is slightly higher than the pore pressure. The required back-pressure is calculated and applied when the pumps are switched off, in order to avoid any influx.

## 5.1.2. Method selection / viability of the options

**Despite of the fact, that in the previous sub-chapters was stated, that MPD operation is not required for the Skarv/Idun reservoir condition due to relatively low drilling risks, simplified approach how to conduct an MPD operation (CBHP) from a semi-submersible drilling rig will be presented.**

Factors determining the viability of MPD for a given well are:

- The available mud type or weight range;
- Budget for the operation;
- The quality and purpose of the well;
- Availability of alternative options;
- Economic constraints;

Even if the candidate appears to be suited to MPD, often one of the other parameters mentioned above precludes application of the technique. In the Skarv/Idun case there is more than one parameter that precludes using MPD. Nevertheless, the main factor against the MPD is the availability of other options (conventional).

## 5.1.3. Special Drilling Equipment

Equipment determination and selection is also a part of feasibility study. Specific equipment to contain or manage the pressure at different levels is required for MPD, along with the conventional drilling equipment available on the rig. The essential equipment for Constant Bottom-Hole Pressure MPD variation from a semi-submersible drilling rig consists of (detailed description and purpose of them is described in the chapter 5.3.2.):

- Rotating Control Device (specially designed for deepwater drilling applications),
- MPD Choke Manifold;
- Back-Pressure Pump;
- Pressure monitoring software;

### 5.1.4. HAZOP and HAZID

An appropriate planning and execution plan is a crucial part of successful MPD. Proper HAZOP (hazard and operability study) and HAZID (hazard identification study) plans, appropriate contingency plans, equipment evaluation and pressure testing, training of the rig crew and other staff members in MPD procedures are also very important in the planning and execution phase.

While candidate selection phase is in progress, the **HAZID** may consist of a simple list of anticipated problems to be encountered during MPD operations. It helps to determine the requirements and limitations of many of the parameters mentioned earlier.

**HAZOP** plan is more detailed and can include the preliminary required procedures to prevent or mitigate the hazards identified at this stage. This contingency planning may reveal additional aspects of the operation that can bring into question the viability or applicability of MPD for a particular well. For example, a certain required procedure identified may result in an equipment requirement that cannot be met for a certain well. If an alternative cannot be found, MPD may be eliminated as an option.

## 5.2. Challenges due to floating application of MPD on the Skarv/Idun field

Challenges regarding to the floating application of MPD on the Skarv/Idun field are mostly associated with dealing with rig heave and preventing therefore surge and swab effects during making connections. Therefore it will be difficult to maintain the value of Bottom-Hole Pressure in a CBHP MPD variation at the constant level.

It should be taken into consideration, that floating application of Managed Pressure Drilling has not been used so far (2011) on the harsh Norwegian Continental Shelf offshore environment. Therefore before conducting an MPD operation special well control procedures has to be introduced (according to the Petroleum Safety Authority Norway requirements), rig crew has to be carefully trained and suitable method has to be selected.

## 5.3. Preparation and planning

Every good project manager knows that inadequate planning is a top reason for project failure. In spite of this, the industry continues to undertake projects seemingly at the last minute, and even when minimal planning reveals that success is unlikely, the project continues on once started. This is never good, and in the case of MPD, it can be catastrophic. Preparation though includes more than just good planning. It must include the resources required to carry out the plan.

Appropriate procedures, prepared with appropriate expertise, are necessity. The basic procedures of MPD are similar, no matter the application. However, the details related to each specific application, though they may be small, are vital. Even procedures for twin wells in the same reservoir usually will need some modification between wells.

Any Managed Pressure Drilling application must be approached from a holistic viewpoint and must address the entire drilling system. An experienced drilling engineer should prepare all MPD procedures. Likewise, an experienced drilling supervisor familiar with all aspects of the drilling process and capable of handling any drilling situation should be in responsible charge of execution of the procedures.

As with any MPD pre-well study, the objective is to understand the operational environment so that procedures could be developed and the proper equipment selected. The consequences of not understanding the operational window can lead to the selection of equipment that is not suited for the job. Improper planning can result in having too much or not enough equipment on location, and either scenario can be costly. Additional equipment and personnel will drive up the Authorization For Expenditure costs, while the second situation results in occurrence of non-productive events and possible reservoir damage, which also affects well costs.

### 5.3.1. Importance of hole cleaning

Poor hole cleaning has been long acknowledged as one of the largest obstacles to success in underbalanced drilling. With MPD, hole cleaning is even more significant.

The upper limit is typically a frac-gradient or other leak-off limit. The general tendency is to decrease circulation rate in order to minimize friction and reduce the potential to exceed the upper limit. However, reduced circulation normally results in reduced ability to clean the hole. Since the mud-weight may be closer to pore pressure while utilizing Managed Pressure Drilling, the rate of penetration may actually be higher than in conventional drilling. The combination of increased cutting loading and decreased circulation rate has a multiplying effect, increasing the chance of pack-off in the annulus, high torque and drag, and eventually worse problems such as stuck pipe, twist off etc.

## 5.3.2. Appropriate Equipment Arrangement

Appropriate arrangement of the equipment is a vital part of the MPD planning, since using of an inappropriate equipment arrangement can lead to serious problems. Main danger when using too much equipment and/or too high level of complexity for the chosen application are the excessive costs (project may be a technical success but fail in an economic sense). On the other hand, the use of too little equipment and/or too much simplification of the equipment arrangement runs a very real risk of causing a technical failure, which almost invariably will result in an economic failure of the well.

The setup for MPD operations in a closed wellbore system is shown in the figure below (Fig.51.). The Rotating Control Device is installed on top of the annular preventer and closes the wellbore around the drill pipe. The outlet from the Rotating Control Device is split between the main return flow line and the MPD choke manifold. The MPD choke manifold is installed in parallel with the rigs main flow line and in parallel with the rigs conventional choke manifold. This set up allows conventional circulation methods as well as circulation through the MPD manifold. Back pressure can be applied to the well at any time when the MPD manifold is being used. Any gas being circulated out using the MPD can be safely vented trough the mud gas separator. If surface pressure exceed the Rotating Control Device pressure ratings the whole well control set up can be quickly switch to the standard drilling well control equipment. During tripping operations circulation with the trip tank can be done via the MPD manifold or via the existing flow line.

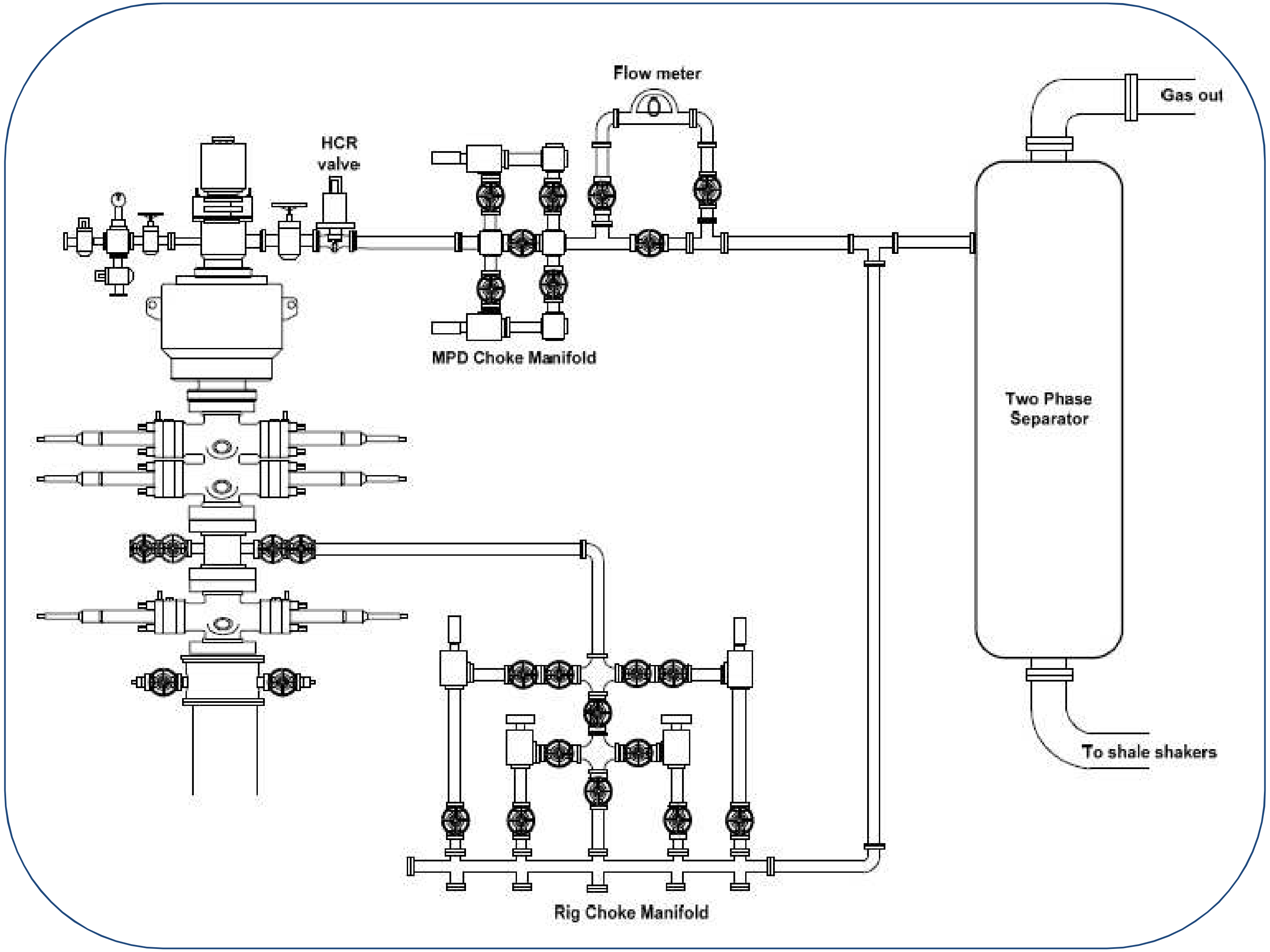


Fig. 51 MPD set up for the Constant Bottom-Hole Pressure variation (Source: SPE 143099; Ref. no 35)

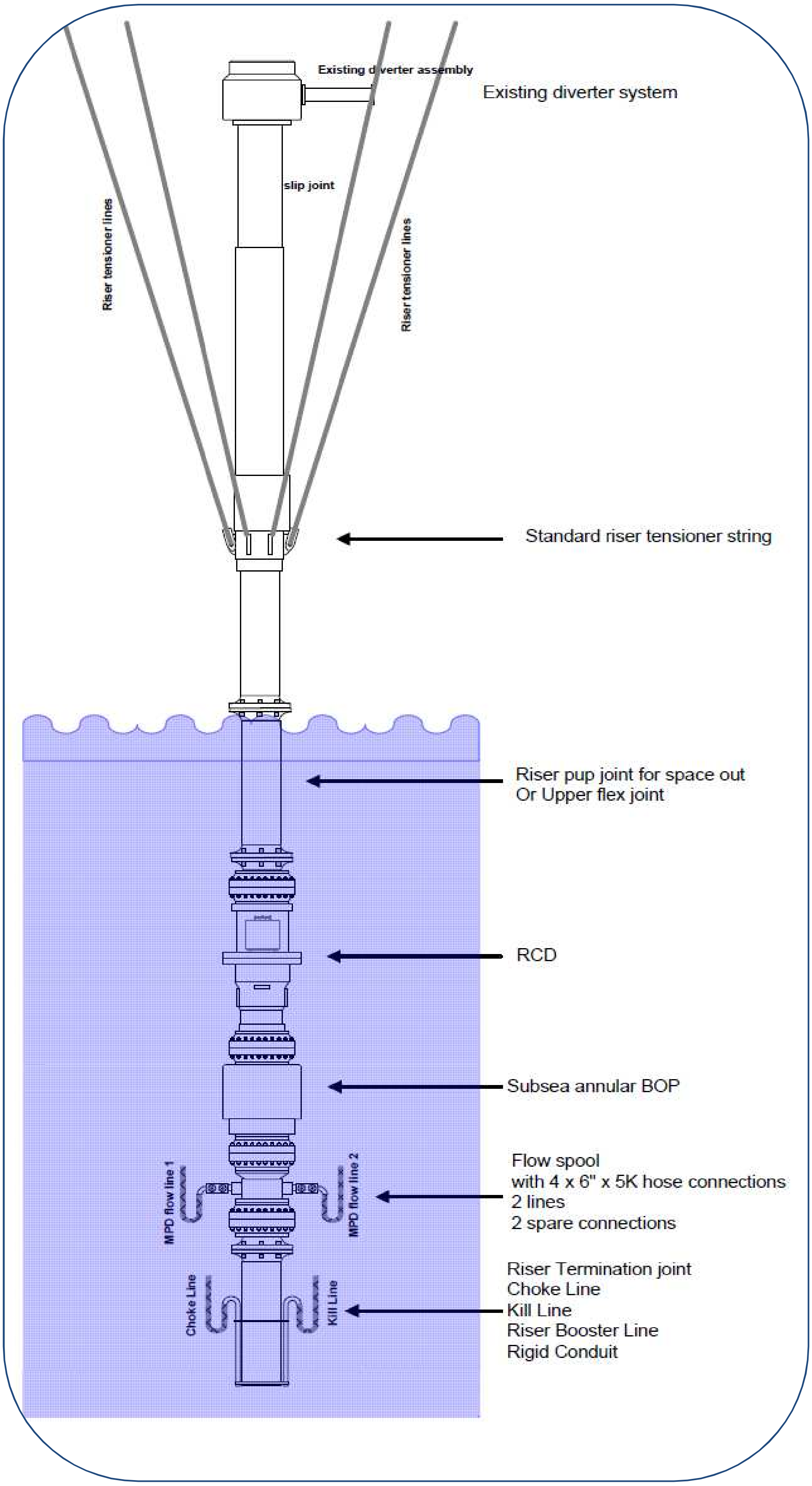


**Fig. 52 Below Slipjoint MPD system dedicated for deepwater applications (Source: SPE 132049; Ref. no 23.)**

The marine riser will be the standard marine riser system as is on the rig. The risers are normally equipped with choke, kill lines, a booster line, and sometimes with BOP control lines. These lines are all terminated in the so-called termination joint, which often is the same as the lower slip joint and tension ring. The riser lines must be reviewed with regards to the installation of the RCD system but it is perhaps best that the termination of the riser lines is done below the RCD system[23].

**Riser Circulating Spool**

A spool needs to be designed that allows flow from below the annular preventer and Rotating Control Device. This flow spool allows the annulus to be connected to the rig by using four high-pressure hoses back to the moonpool.

**Annular preventer**

A 21 1/4'' subsea annular preventer in this configuration is installed above the flow spool. It will allow the riser to be closed, even if the rotating control diverter is not functioning or its not being used. This Annular is controlled by a separate panel, which is not part of the BOP control system, which leaves the subsea BOP panel un-touched.

**Rotating Control Device**

A special Rotating Control Device model dedicated to the offshore environments is used. With the installation of the RCD below the water line, a number of modifications have to be made to the RCD control system. Rotating Control Device is now exposed to water pressure as well as the rig motions. The control system for the RCD will have to be compensated for heave and spooled much like the BOP control lines. The RCD has a bore of 18 5/8'' and a protective sleeve normally installed in the hydraulic latch mechanism, which allows all equipment used for 17 1/2'' hole sizes. When the bearing assembly is installed, its nominal Internal Diameter is 8 3/4 '' and this bore makes it suitable for 6 5/8'' drill strings that are often used in deepwater applications. The pressure rating of the Rotating Control Device is 2000 [psi] static pressure. This value decreases with increasing rotational speed. This static pressure is also close to the maximum rating of most marine riser seals and allows a good range of mud weights to be covered. The seal and bearing assembly for the RCD are being run through the rotary table and Slipjoint. The Internal Diameter of the Slipjoint will need to be reviewed to ensure that the bearing assembly can be run through all of the Slipjoint equipment.

**Choke Manifold**

If it is required to have pressure applied to the surface of the well and to ensure that any gas in the riser can be safely circulated out, it is proposed that an MPD Secure Drilling Choke manifold is used (Weatherford solution). These fully automated choke manifolds allow early kick detection and automatic pressure control on the wells. One of the issues that has been found is that there is little information about drilling riser pressure rating from the manufacturers. The seals on the riser connectors are often quoted as the limiting factor. Riser ratings are normally expressed in mud weight terms. In deepwater is a considerable pressure at the bottom of the riser and pressures inside the riser can change easily by 1000 - 2000 [psi] or even more due to hydrostatic pressures because of mud weight changes. Although the lower riser joints for deepwater are normally strengthened to deal with potential collapse issues, the internal pressure in the riser remains a subject that is not well defined. The internal pressure loads are assumed to be generally caused by the hydrostatic pressures of the drilling fluid densities. The internal pressure ratings in the operating manuals of the risers are defined as the pressure ratings of the tube but do not include any references to the pressure ratings of the riser connectors.

**Automatic fill up valves**

The riser fill-up valve is designed to prevent collapse of the riser if the level of drilling fluid drops due to intentional drive-off, loss of circulation or accidental line disconnection. While normal drilling operations, the valve's internal sleeve is kept closed by a spring. Then riser pressure drops, hydrostatic pressure pushes up on the sleeve and overrides the spring force. This causes the valve to open and sea water enters the riser, equalizing the pressure and preventing collapse. These valves are automatic opening and open then the combination of mud column pressure and pilot compression spring drops between 225 and 325 [psi] below the ambient ocean pressure. Once the fill-up valve opens, it remains in the open position until commanded to close by a disable or reset signal from the surface.

## 5.4. Installation, commissioning, testing and training

All necessary equipment for the Constant Bottom-Hole Pressure MPD has to be placed, connected and rigged up in a proper manner. As mentioned before Rotating Control Device is dedicated to the deepwater conditions and is placed below the water line (Weatherford's Below Slipjoint System). MPD choke manifold is placed on the rig floor and requires about 6 [$m^2$] space on the rig and weighs about 12 [tones]. Additional space is also needed for the Back-Pressure Pump. Dedicated Control System is also installed and connected to the real-time pressure and temperature monitoring equipment. Values of the critical parameters are showed on a special panel and allow the MPD operator to have situation under control. All the piping system connecting that equipment has to have pressure ratings appropriate for the requirements. MPD equipment has to be installed to allow safe switch between the MPD mode and the conventional mode in case of necessity. It should be also mentioned, that there is a need for slight modifications on the rig (to allow place the MPD required equipment) but all rig safety equipment remains unchanged. Moreover, special well control procedures for kick situations according to the Norwegian Petroleum Safety Authority requirements have to be prepared. Rig crew has to be properly trained before an MPD operations commence. Appropriate training, delivered at the correct time, is an integral part of any successful MPD project. Training program for the staff should be developed specifically for the project. Initially, drilling supervisors and project personnel should to receive MPD-specific classroom training that covered equipment, benefits and limitations, operational and emergency procedures, hazards, and well control. Furthermore, prior to each well section drilled with using Managed Pressure Drilling, training should be given to the wellsite crew and should includes a general overview of MPD and equipment, roles and responsibilities, operational and emergency procedures, communication, and procedures to ensure safety to personnel and the environment. Only after commissioning, testing and required trainings completed Managed Pressure Drilling operations can begin.

## 5.5. Well control procedures

Before commencing MPD operations, well control procedures have to be specified. These procedures include special operations, if a kick situation occurs.
If the influx is detected is small and it has a low kick intensity, it is very possible to circulate out the kick using Managed Pressure Drilling equipment. The “driller's method” is usually used for this and the MPD operator must now hold drill pipe pressure constant, whilst the driller circulates out the kick. Once the influx hits the surface equipment, the MPD operator must also divert any gas away from the main flow line to a suitable mud gas separator.
This assumes that all MPD operators have the required experience and understanding of well control operations. Prior to any MPD operations being conducted, it must be verified that all MPD personnel operating the choke understands the procedures and actions required when a kick is detected. The MPD operator must fully understand the well control situation. Both the MPD operator and the driller must keep a close eye on the surface pressures to ensure that these remain within the limits of the equipment being used.
One of the big advantages of using the MPD equipment for well control is the fact that the pipe can be moved up and down and rotated and stuck pipe incidents, often associated with well control operations can be avoided.
If at any time something goes wrong during an MPD well control situation, the driller must be able to stop the pumps and shut in the well using the BOP's and then continue the well kill operation using the rig choke manifold.
Closed well bore systems like in Managed Pressure drilling provide significantly better kick detection and kick control systems. The inflow volumes detected can be much smaller when compared with conventional kick detection systems. Procedures must be in place prior to drilling operations commencing that fully document and communicate what actions are taken if a kick is taken. It must be clear to the operator, the drilling contractor and to the MPD provider who is doing what and what actions are to be taken.
Expected volumes and pressures must be defined prior to drilling and a clear well control matrix and well control procedures must be in place. The decision of circulating and controlling the well must be documented, communicated and well understood by all parties to ensure that everybody what actions are required.

The driller must have up to date pre kick sheets as well as slow circulating rates and pressures. Maximum allowable pressures must be clearly displayed on the drill floor and on the MPD choke controls.

The controls of the MPD choke manifold should be on the rig floor in close proximity to the driller. This will ensure that communication between the driller and the MPD operator is without any interruptions and does not rely on phone or radio systems.

Limitations of mass flow meters must be understood and documented. If gas cut mud is being circulated and well control is crucial then drilling must be suspended until the mass flow meter is once again able to detect flow.

## 5.6. Possible problems

- Due to significant rig heave in the harsh Norwegian Continental Shelf areas it will be very difficult to maintain the Bottom-Hole Pressure value at the same level in the Constant Bottom-Hole Pressure MPD variation , both during drilling and tripping (surge and swab effects);
- Drill pipe condition has an impact on the life of the Rotating Control Device rubber elements. Due to the drill pipe grooves and hard banding life of the rubber sealing elements can be significantly reduced. Therefore drill pipe condition needs to be reviewed to ensure that rubber life is maximized;
- If there is a rough weather during rig up operation it may be required to have the riser Slipjoint pinned and supported from the moonpool to allow safe installations;

# 6. Comparison of drilling concepts on the Skarv field

Well **6507/5-6 S** has been chosen as a case well. Well 6507/5-6 S is planned as an exploration well into the Snadd North structure. It will be drilled from the Skarv A template and is planned to be sidetracked to a highly deviated producer, if successful in finding hydrocarbons of economic value and acceptable reservoir quality. The drilling of the well and its sidetrack from the Skarv A template allows long term production testing of the Snadd North. This will resolve two main uncertainties for long term well productivity, which are: water influx and stratigraphic compartmentalization. In this chapter two different drilling concepts for that well will be shown. One of them is drilling conventionally (with open to atmosphere mud return system) and the other is drilling with closed and pressurizable mud return system (by taking advantage of using Managed Pressure Drilling technology).

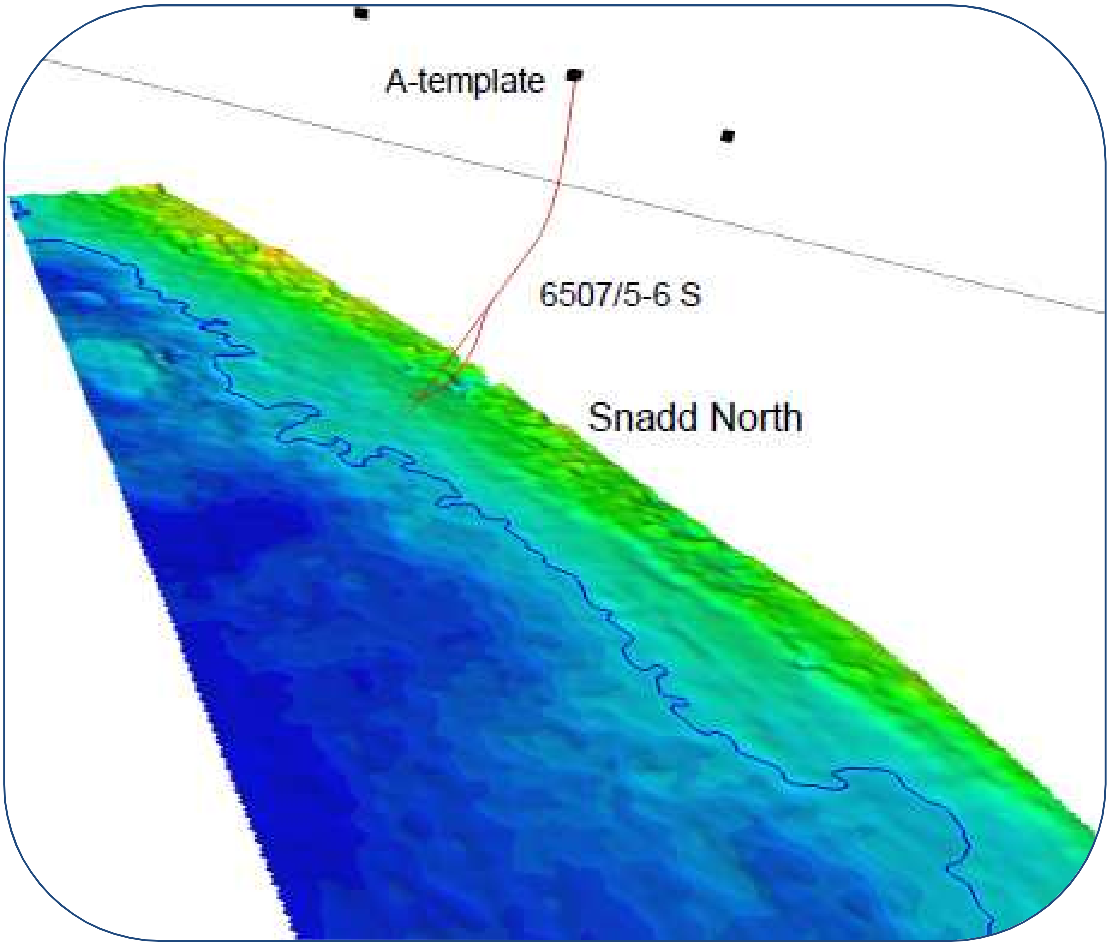


Fig. 53 The Snadd North prospect showing the location of exploration well 6507/5-6 S and a planned horizontal sidetrack to a producer (perspective view)

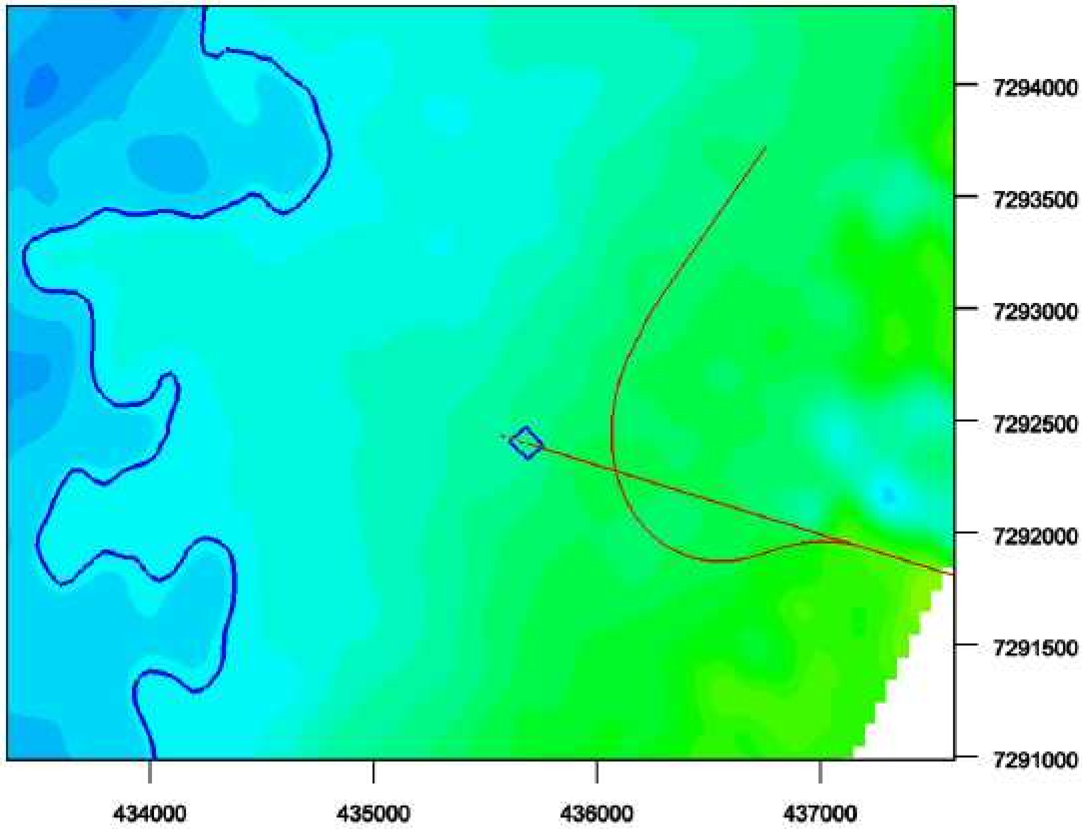


Fig. 54 The Snadd North prospect showing the location of exploration well 6507/5-6 S and a planned horizontal sidetrack to a producer (top view)

## 6.1. Conventional drilling program

Conductor casing (30") will be set 85 m below seabed and the setting depth for the 18.7" casing is about 1090 [mTVDss]. Drill-bit size for the first section (conductor casing) is 36" and for the second section (surface casing) is 24". Drilling mud for those sections will be seawater and bentonite sweeps for hole cleaning and weighted bentonite mud in the hole when running casing. Prior to drilling the 24" section, a pilot hole for potential shallow gas detection will also be drilled to just below the 18.7" casing setting depth at around 1100 [mTVDss]. Hole inclination will be built up to around 20° in the 24" section. The 17 1/2" section will be drilled to around 1850 [mTVDss], where the 13 5/8" casing will be run and cemented. The drilling mud in the 17 1/2" section will be Carbo sea OBM. The 12 1/4" section will be drilled just into the reservoir and then cored. As it may be difficult to definitively determine whether the reservoir is dry or contains hydrocarbons with only the top few meters of reservoir data, a core will be taken regardless of initial saturation. The plan is to core at least 25 [m]. After the coring, the well will be drilled to TD and wireline logs will be run for formation evaluation. Due to about 60 [deg] inclination in the well, contingency for running the logs on TCL or open hole tractor will be planned for.

The mud in the 12 1/4 ” section will be Carbo sea OBM. After logging the open hole will be plugged back with cement into the 13 5/8” casing shoe and a shallow plug will be run in the 13 5/8” casing for temporarily abandonment of the well. If the well is dry and the well will be permanently abandoned, the 30” and 18.7” casings can be reused to another well target. The 13 5/8” casing is probably in an unfavorable direction and will probably have to be pulled prior to using the well to another target. If a new well target is not known, well should be leaved in the same way as planned for temporary abandonment and do permanent abandonment later and not spend rigs days at this stage to do a permanent P&A.

For a future production well the 13 5/8” casing shoe is planned as the kick off point for the production well and the well path is chosen to be able to combine both the exploration well and a future production well.

As per the PDO cost and time estimates and the supporting Drilling & Completion Uncertainty Statement (DCUS), the well will be drilled, logged and temporarily abandoned in 57 days, at a total cost of 52,5 mill USD. This cost includes a 25% chance of having to run a 9 5/8” drilling liner due to the high hole in the 12 1/4” hole section.

## 6.2. Managed Pressure Drilling solution

In spite of not very narrow pressure window, the most viable MPD solution to deal with drilling related challenges for the Skarv/Idun conditions is the Constant Bottom-Hole Pressure MPD variation. To make it possible, Below Slipjoint MPD System developed by the Weatherford is recommended to be used. Below Slipjoint System is specially designed for floating application of Managed Pressure Drilling. In that configuration Rotating control Device is placed below the water line and exposed to water pressure and rig motions. To takes fully advantages from utilizing MPD, CBHP should be designed “proactive”. Constant Bottom-Hole Pressure MPD is projected as a viable alternative to conventional drilling to drill in the 12 1/4' ' reservoir (between 1850 [mTVDss] and TD) section. Main drilling risks, which are going to be mitigated or prevented by utilizing MPD in that sections are: differential sticking during drilling in the reservoir with high overbalance, wellbore instability in overburden in high inclined section of the well and severe mud losses. This can be achieved by precisely managed pressures in the wellbore, which allows using lighter than conventional drilling fluid and therefore provides only slight overbalance in the well. First sections should to be drilled conventionally with conventional wisdom drilling mud.

This technology (CBHP MPD) from the technical point of view can be applied on the Transocean’s Polar Pioneer semi-submersible drilling rig. Nevertheless, to be truly effective, MPD must safely reduce overall drilling costs. In the Skarv/Idun conditions due to relatively low drilling-related risks overall cost of the well with utilizing MPD is higher than with drilling conventional way. Moreover, most of the drilling related challenges can be overcome using conventional methods and techniques, which makes using MPD not necessary.

## 6.3. Drilling-related benefits of using MPD technology on the Skarv/Idun field

Major reason for utilizing such technologies as an MPD is the inability to drill the well using conventional overbalanced drilling methods. In the Skarv/Idun conditions there are some possibilities to drill conventionally and therefore using an MPD system is not the "one and only one" option to overcome drilling challenges. Nevertheless, utilizing a closed pressurizable mud return system would cause some advantages:

- Reducing HSE risks by improving kick/gas detection and therefore increasing safety in drilling operations;
- Improving drilling performance by increasing Rate of Penetration due to drilling with lighter fluid;
- Improving drilling performance by extending the bit life;
- Improving drilling performance by minimizing differential sticking;
- Improving performance by reducing Non-Productive Time;
- Improving wellbore stability in highly inclined and horizontal sections;
- Reducing drilling fluid losses;

## 6.4. Reservoir/Production - related benefits of using MPD technology on the Skarv field

The reservoir-related or production-related benefits of Managed Pressure Drilling are quite significant when compared with conventional overbalanced drilling. Due to drilling with Bottom-Hole Pressure equal or slightly above the formation pressure formation damage and/or skin factor values can be considerably reduced. Therefore, these benefits can be seen through higher productivity of MPD wells as a result of reduction of drilling-induced damage.

## 6.5. Economic viability of using MPD technology on the Skarv/Idun field

Average cost of the well on the Skarv/Idun field when drilling conventionally is about 57,3 million USD. Mean drilling performance is equal to 92 meters per day. Average time for drilling and completion a well on the Skarv/Idun is equal to 81 days. 28% of that time is classified as a Non-Productive Time (including 8% WoW). It should be considered that some of those costs will change, when drilling with using Managed Pressure Drilling technology. Deploying MPD technology on the Skarv/Idun involves excessive additional costs for the operator.

These costs can be generated due to:

- Necessity for having additional equipment such as Rotating Control Device, Choke Manifold, Back-Pressure Pump, piping etc. and associated with that installation and rental costs;
- Necessary rig modifications (not significant due to limited modifications required);
- Required rig personnel trainings (general overview of MPD and its equipment, roles and responsibilities, operational and emergency procedures, communication and procedures to ensure safety to personnel and environment);

On the other hand deploying Managed Pressure Drilling can reduce drilling related costs by:

- Reducing NPT and increasing ROP;
- Reducing mud costs by lower density of the mud and less losses;
- Improving wellbore stability;
- Reducing potential for differential stuck pipe;

Nevertheless, due to possibilities for overcome drilling challenges in conventional way, additional expenditures spent on the required equipment, its installation, maintenance and training of the rig crew are much higher than potential benefits caused by reducing NPT and increasing drilling performance. Therefore these additional expenses are not justified in the Skarv/Idun case. In the most optimistic scenario, if the Non-Productive Time would be reduced from 28 [%] to 20-21 [%] and Rate of Penetration increased by 7-8 [%], therefore reducing average time spent on drilling by about 3 days. Even then, these additional expenditures are not justified, due to higher expenses created by deploying MPD, than benefits from shorter time spent on drilling.

# 7. Conclusions

Managed Pressure Drilling is an evolving technology which is supported with unique techniques and specialized devices. The combination of those techniques and devices direct MPD to be an invaluable technology which has potential for mitigating drilling hazards, improving drilling performance and increasing production rates. Moreover, MPD is an advance form of drilling supported with other technologies and proactive planning, which leads MPD not only to drill challenging but also undrillable wells.

Nevertheless it should be mentioned that MPD technology has been used since now (May 2011) only in some parts of world; most of the offshore applications were from fixed platforms, there were also floating applications but in relatively mild offshore environments (like in Malaysia and Indonesia). On the Norwegian Continental Shelf MPD has been deployed only from fixed platforms on the Gullfaks C field (from skirt piled concrete platform) and two HP/HT fields: Kvitebjørn (from fixed steel PDQ platform) and Mandarin East (from heavy duty Jack-Up rig). Managed Pressure Drilling technology was also evaluated as an option on the HP/HT Kristin field (from the semi-submersible drilling rig), but after careful planning and selection process finally MPD has not been used. The main drivers not to use MPD on Kristin field were that a lot of improvements in equipment needed to conduct an MPD operation in safe and efficient manner. The outcome of the in-depth evaluating process was, that were more constraints against conducting MPD than potential benefits of using this technology, due to too many challenges to overcome (related to floating application of MPD). Managed Pressure Drilling was the last option on Kristin (in case that there is no other solution), however drilling challenges on that field were prevailed in a safe way without using MPD. Therefore MPD can be classified as an unproven technology in harsh Norwegian Continental Shelf offshore environments. Lesson learned from the Kristin and Gullfaks C (there was an accident on the Gullfaks C in 2010 during drilling in MPD mode) to the Skarv/Idun development is that choosing MPD should be preceded with careful preparation, planning and selecting process; hazards caused by deploying closed mud system should be also considered. MPD operations from the Transocean Polar Pioneer on the Skarv field should be utilized **ONLY** if there are no other options to overcome drilling challenges and improving drilling efficiency on that field.

## 7.1. Discussion on the Study

The main aim of this Master's Thesis was to evaluate the feasibility and applicability of using Managed Pressure Drilling on the Skarv field in which PGNiG Norway AS has an interest (11,9175 [%]). An MPD technology was considered as an option, which may mitigate at least some of the drilling challenges/hazards. Those drilling related challenges/hazards (shallow gas, wellbore instability, swelling clays and differential sticking) were main drivers for conducting this feasibility study. As a case well on the Skarv field was chosen well 6507/5-6 S, which will be drilled from the Skarv A template. Case drilling rig was 4$^{th}$ generation semi-submersible Transocean Polar Pioneer, which has been contracted to drill wells on the Skarv/Idun area in the following years. As mentioned before well 6507/5-6 S is planned as an exploration well into the Snadd North structure and is planned to be sidetracked to a highly deviated producer if successful in finding hydrocarbons of economic value and acceptable reservoir quality. In that area there is relatively high risks of wellbore instability in overburden in highly deviated wells (like 6507/5-6 S), shallow gas presence, shallow section boulders, clay swelling in Brygge/Tare/Tang interval (between 1500 and 2000 [m] below the seabed) or differential sticking while drilling and coring.

Selection process have been conducted, suitability of the MPD variations have been evaluated and additional equipment and qualified needed to an MPD operation was assessed. Furthermore, economic viability was evaluated. The outcome of those processes was that Managed Pressure Drilling operation is **NOT REQUIRED** on the Skarv/Idun field. According to the Sauduri's selection process flow diagram (Fig. 49) most of the drilling related challenges can be overcome in conventional way by changing mud rheology, using different drill-bit types, changing WOB, pumping rate etc. MPD operation can indeed slightly reduce a Non-Productive Time and improves a HSE issues (due to shallow gas presence above Kai formation), but due to a lot of efforts with employing this technology, MPD operation can also significantly increase overall drilling cost, exceeding therefore Authorization For Expenditure (AFE). Those additional expenditures would be justified only if deploying this technology would significantly reduce Non-Productive Time, improves therefore drilling efficiency or considerably improve Health, Safety or Environmental issues like with the risks of presence shallow gas or $H_2S$. On the Skarv / Idun field as mentioned before can be mitigate in less costs without deploying MPD and furthermore there are other risks that cannot be mitigated by the MPD, but which can also have negative influence on the drilling performance and/or HSE issues. It can be boulders in shallow section and swelling clays at Brygge / Tare / Tang interval. Those challenges can be also mitigated in conventional way.

## 7.2. Recommendations

Different, both conventional and MPD drilling concepts of dealing with the Skarv/Idun drilling related challenges mentioned above were evaluated. The outcome of this analysis is that **it is possible (from the technical point of view) to conduct an MPD operation from the Polar Pioneer semi.** Rig has enough capacities and capabilities, there is a space on the platform to place all necessary equipment (even for the Choke Manifold and Back-Pressure Pump) and Rotating Control Device can be placed below the Slip-Joint (Weatherford solution). Nevertheless, after selection process and careful evaluating of the possible concepts it turned out, that **MPD is NOT REQUIRED** to be used on the Skarv/Idun reservoir conditions. **Deploying MPD** on this particular field **increase** average **well cost** and overall expenditures, mitigating only slightly some of the drilling related challenges. On the other hand, the **only viable MPD solution is CBHP MPD**, which can overcome most of the expected drilling-related challenges on the Skarv/Idun area. Despite closed pressurizable mud return system can improve HSE issues and improves slightly drilling efficiency, creates additional excessive costs. Therefore **using this variation is not also economically justified**.

**There are other less expensive options to deal with those drilling hazards** on this field:

- Wellbore stability in overburden in high inclination wells can be improved by proper adjusting mud properties and by accurately predicting important features affecting stability like pore pressure, in-situ stress, shear failure and fracture gradient;
- Shallow gas presence (marked as a low to medium risks) can be avoided by appropriate and permanent maintenance of hydrostatic control of the well;
- Differential sticking during drilling in the reservoir with high overbalance can be avoided by:
    - Reducing mud weight as much as possible;
    - Using 'non-stick' drill collars;
    - Using short BHA;
    - Providing a thin mud cake;
    - Mud pills;
    - Rotating drillstring by the Top Drive;
    - Ensuring adequate hole cleaning;
- Swelling clays at the Brygge/Tare/Tang interval can be controlled by mud type and time of exposure; oil base mud should be selected as the likely drilling fluid, so this will reduce the risk of reactive formations;
- Risks caused by the over-pressured layers can be mitigated simply by proper adjusting mud properties;
- Losses at the level experienced during drilling well 6507/5-4 can be prevented by:
    - Using LCM pills;
    - Reducing ROP to limiting cutting load;
    - Minimizing mud rheology;
    - Minimizing wellbore pressure surges;
    - Minimizing mud weight;

# VIII. Nomenclature

| | |
|---|---|
| ABP | Application of Back-Pressure |
| AFE | Authorization For Expenditure |
| AFP | Annular Friction Pressure |
| AFL | Annular Friction Loss |
| API | American Petroleum Insitute |
| BH | Bottom hole |
| BHA | Bottom-Hole Assembly |
| BHP | Hottom-Hole Pressure |
| BOP | Blow-out preventer |
| BP | Backpressure |
| BPM | Barrels per minute |
| CBHP | Constant Bottom-Hole Pressure |
| CCS | Continuous Circulation System |
| CCV | Continuous Circulation Valve |
| CIV | Casing Isolation Valve |
| CMC | Controlled Mud Cap |
| CMCD | Controlled Mud Cap Drilling |
| CPD | Controlled Pressure Drilling |
| CT | Coiled Tubing |
| CTD | Coiled Tubing Drilling |
| DAPC | Dynamic Annular Pressure Control |
| DDV | Downhole Deployment Valve |
| DG | Dual Gradient |
| DGD | Dual Gradient Drilling |
| DIV | Downhole Isolation Valve |
| DSV | Drill string valve |
| DP | Drill pipe or dynamically positioned |
| DwC | Drilling with Casing |
| ECD | Equivalent circulating density |

| | |
|---|---|
| ECD-RT | Equivalent Circulation Density Reduction Tool |
| EDP | Emergency Disconnect Package |
| EDS | Emergency Disconnect System |
| FMC | Floating Mud Cap |
| FMCD | Floating Mud Cap Drilling |
| FP | Fracture Pressure |
| GDT | Gas Down To |
| GOC | Gas Oil Contact |
| GPM | Gallons per minute |
| GWC | Gas Water Contact |
| HAZID | Hazard Identification Study |
| HAZOP | Hazard and Operability Study |
| HP | High Pressure |
| HP/HT | High Pressure/High Temperature |
| HSE | Health, Safety and Environment |
| IADC | International Association of Drilling Contractors |
| ID | Inner diameter |
| KM | Kick margin |
| KVA | Kilo Volt-Ampere |
| LCM | Lost-Circulation Material |
| LMRP | Low marine riser package |
| LRRS | Low Riser Return System |
| LOT | Leak-off Test |
| MFC | Microflux Control |
| MODU | Mobile Offshore Drilling Unit |
| MPD | Managed Pressure Drilling |
| MSL | Mean Sea Level |
| mTVD | Meter True Vertical Depth |
| mTVDss | Meter True Vertical Depth subsea |
| MW | Mud weight |
| MWD | Measurement While Drilling |
| NGU | Nitrogen Generation Unit |

| | |
|---|---|
| NPD | Norwegian Petroleum Directorate |
| NPT | Non-productive time |
| NRV | Non-return valve |
| OB | Overbalanced |
| OBD | Overbalanced drilling |
| OBM | Oil Based Mud |
| OD | Outer Diameter |
| ODT | Oil Down To |
| OUT | Oil Up To |
| OWC | Oil Water Contact |
| P&A | Plug and Abandonment |
| PDQ | Production, Drilling, Quarters |
| PMC | Pressurized Mud Cap |
| PMCD | Pressurized Mud Cap Drilling |
| PP | Pore Pressure |
| RCD | Rotating Control Device |
| RCH | Rotating Control Head |
| ROP | Rate of Penetration |
| ROV | Remotely Operated Vehicle |
| RPM | Revolutions per minute |
| SBP | Surface backpressure |
| SCR | Selective Catalyst Reduction |
| SG | Specific gravity |
| SMD | Subsea Mud-lift Drilling |
| UBD | Underbalanced drilling |
| TD | Total Depth/Target Depth |
| TTRD | Through Tubing Rotary Drilling |
| TVD | True Vertical Depth |
| WHP | Wellhead Pressure |
| WD | Water depth |
| WL | Wireline |
| WOB | Weight on Bit |

| | |
|---|---|
| WoW | Wait on Weather |
| WP | Working Pressure |
| WUT | Water Up To |

# IX. References


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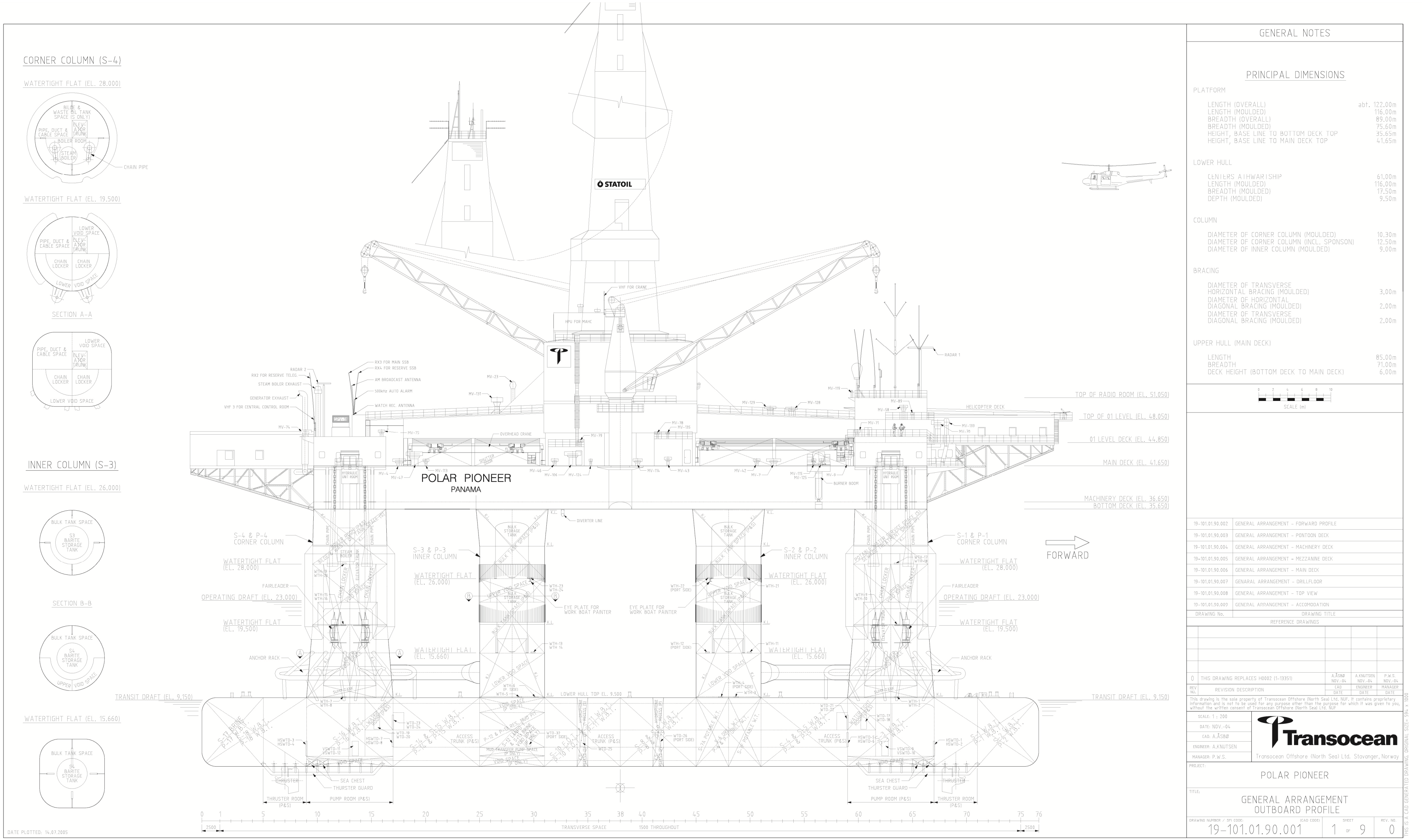


Fig. 55 Polar Pioneer - profile view (Source: Transocean)

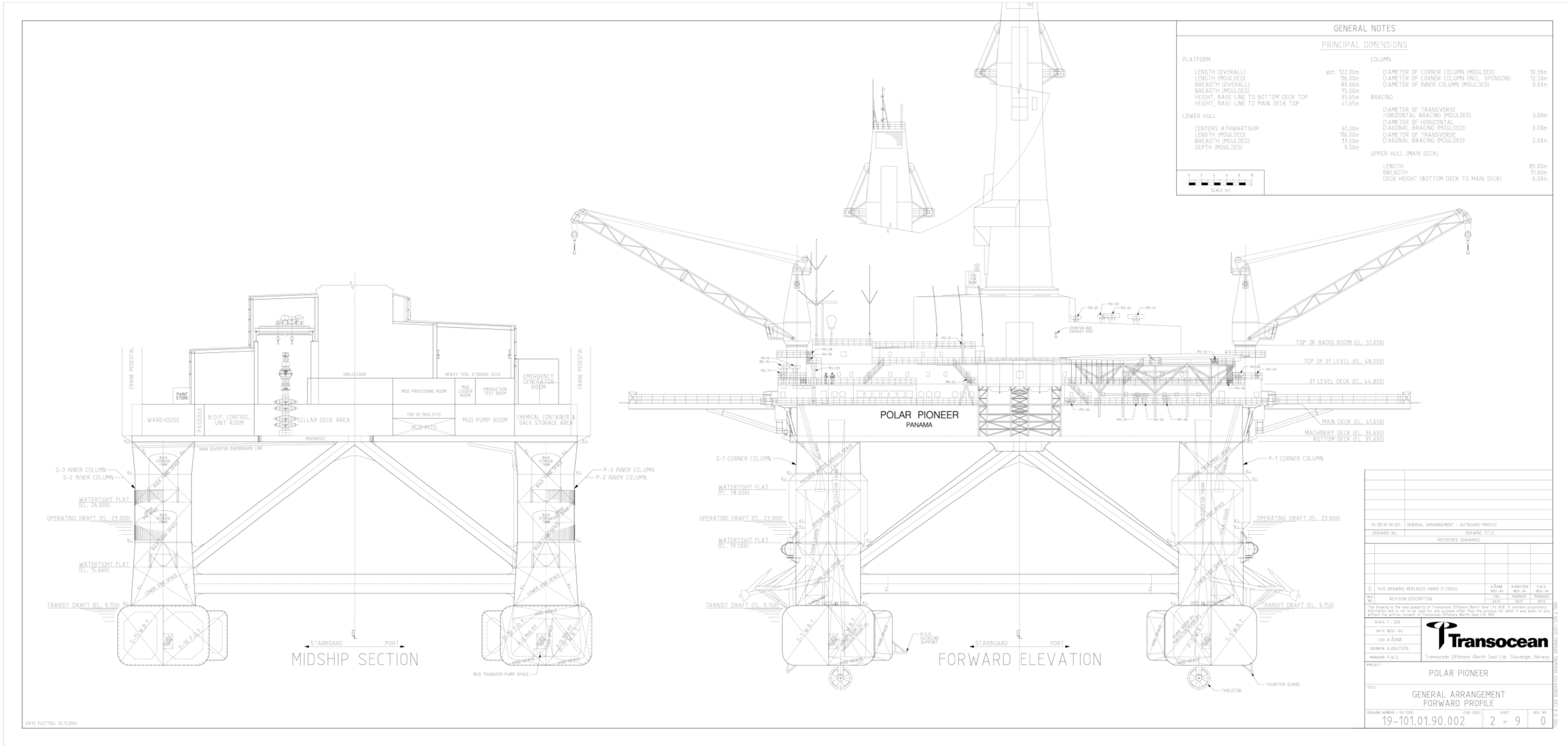


Fig. 56 Polar Pioneer - Front view (Source: Transocean)

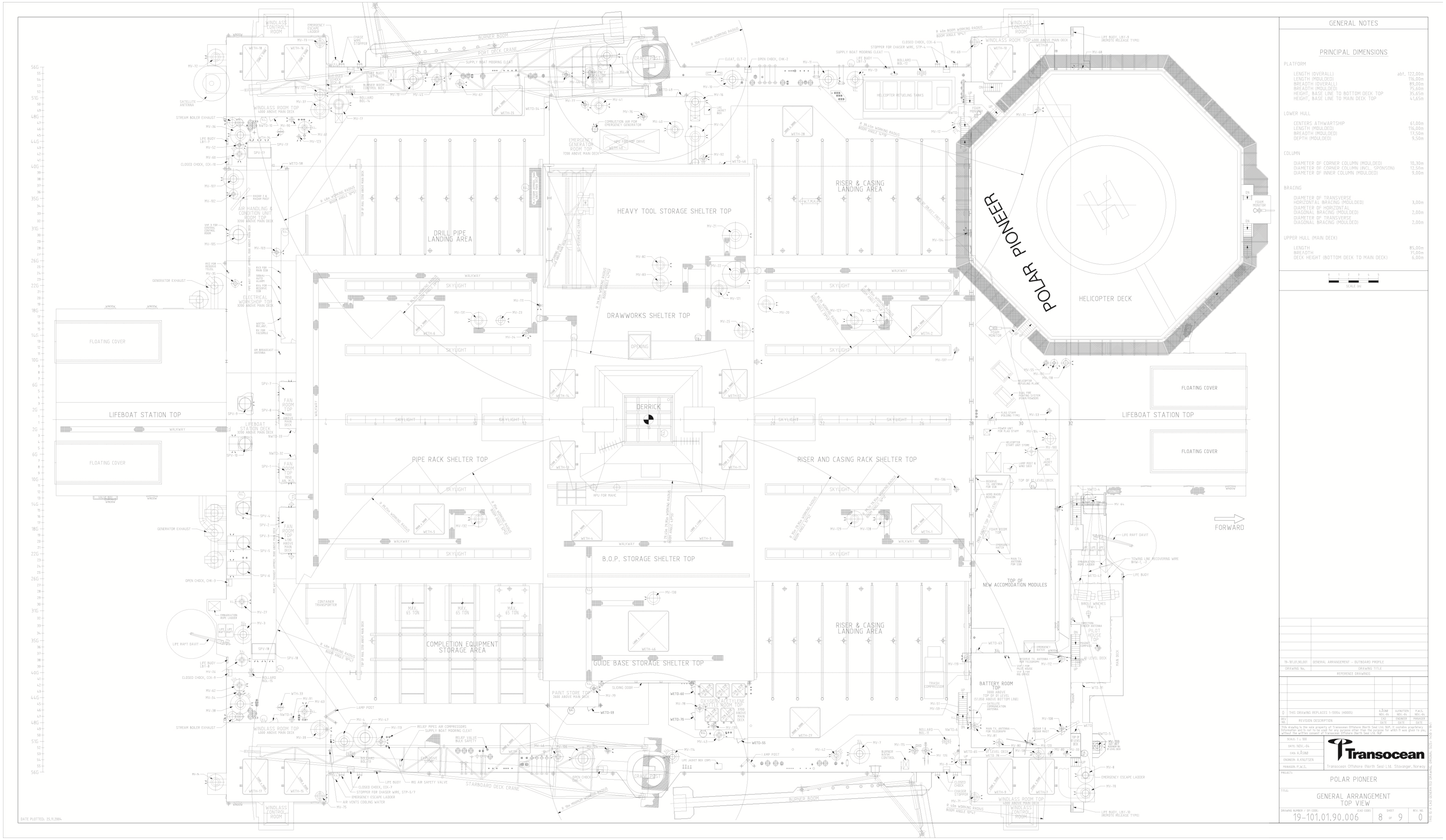


Fig. 57 Polar Pioneer - Top view (Source: Transocean)

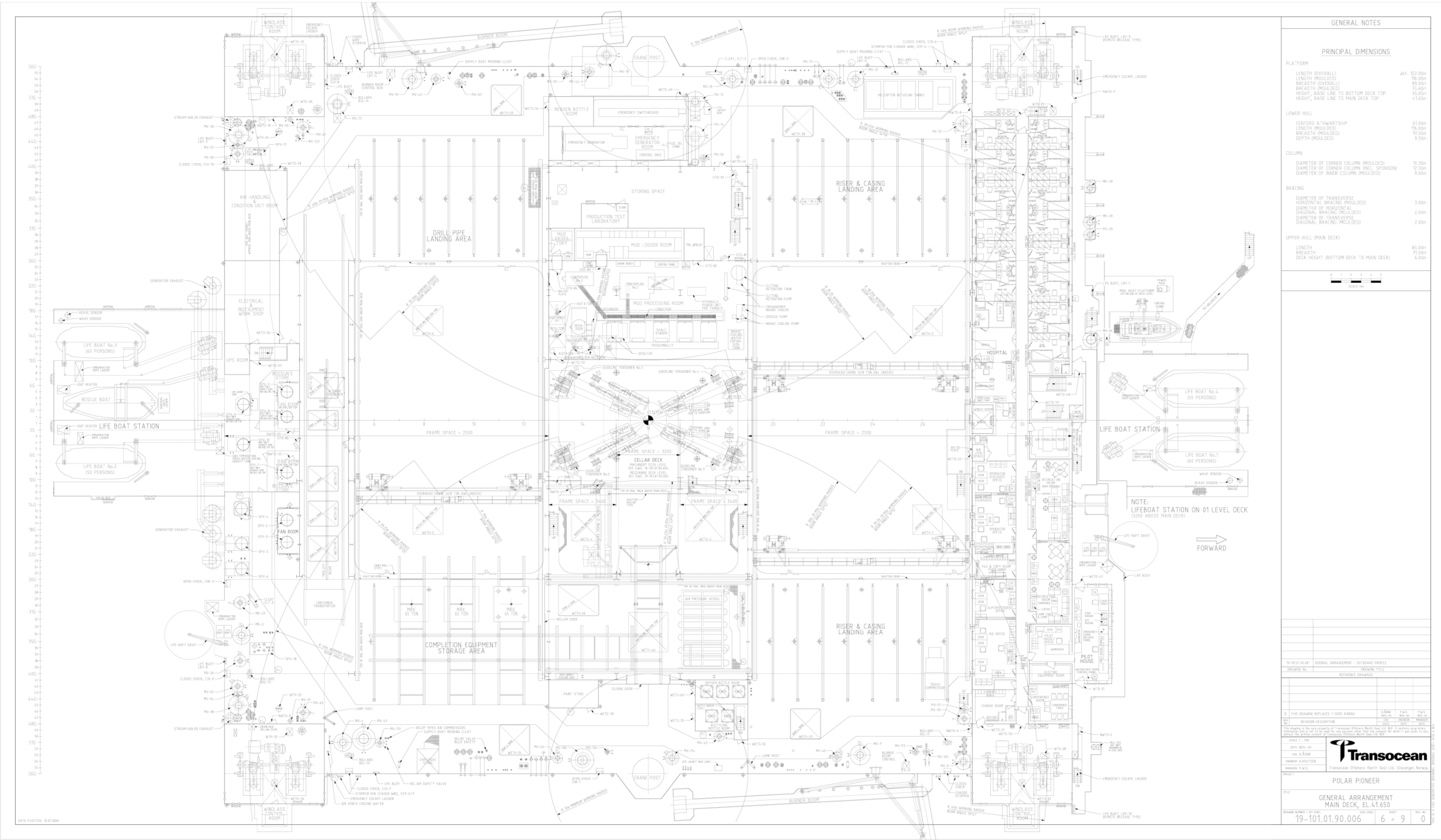


**Fig. 58 Polar Pioneer - Main deck (Source: Transocean)**

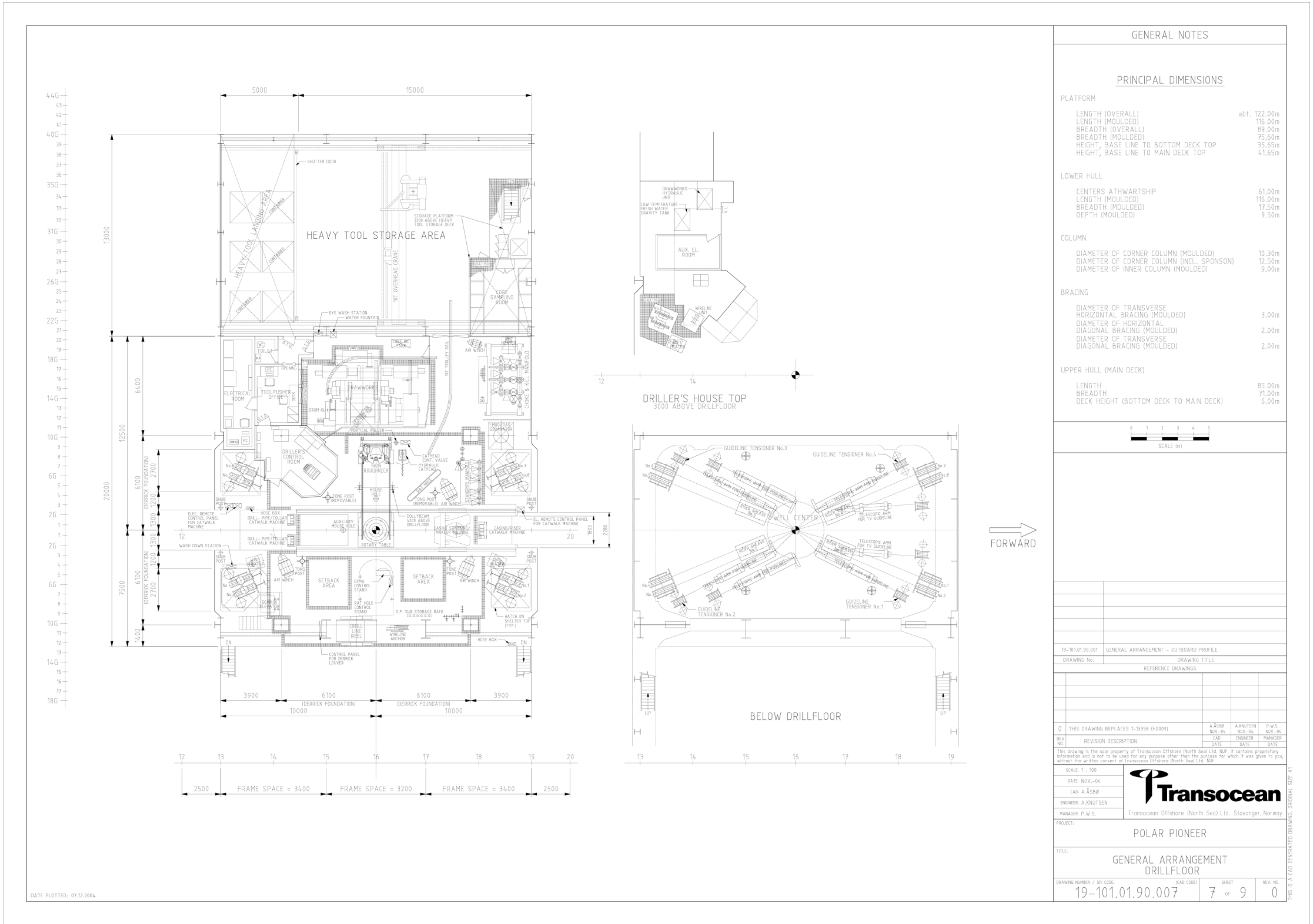


Fig. 59 Polar Pioneer – Drillfloor (Source: Transocean)