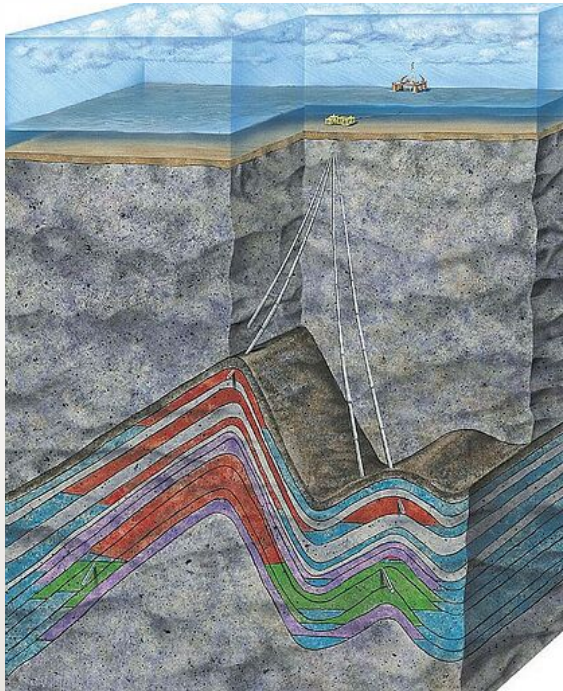


Classification: Internal

Status: Draft



# Drilling in depleted reservoirs

ESRA seminar, 5<sup>th</sup> of March 2009

Line Hoff Nilsen, Leading adviser Well integrity drilling

# Content

## Drilling in depleted reservoirs

- Introduction
  - What is pressure depletion?
  - What are the barriers during drilling?
  - What are the requirements?
- Challenges
- Conventional vs. MPD
- New requirements in StatoilHydro
  - Conventional: Static BHP < Initial pore pressure in reservoir
  - Conventional: Static BHP < Pore pressure in impermeable formations/overburden
  - UBO and MPO



# Pressure depletion

Reduction in the reservoir pressure as a result of producing gas and oil.



Reduction in volume ➡ Reduction in pressure

## Before production:

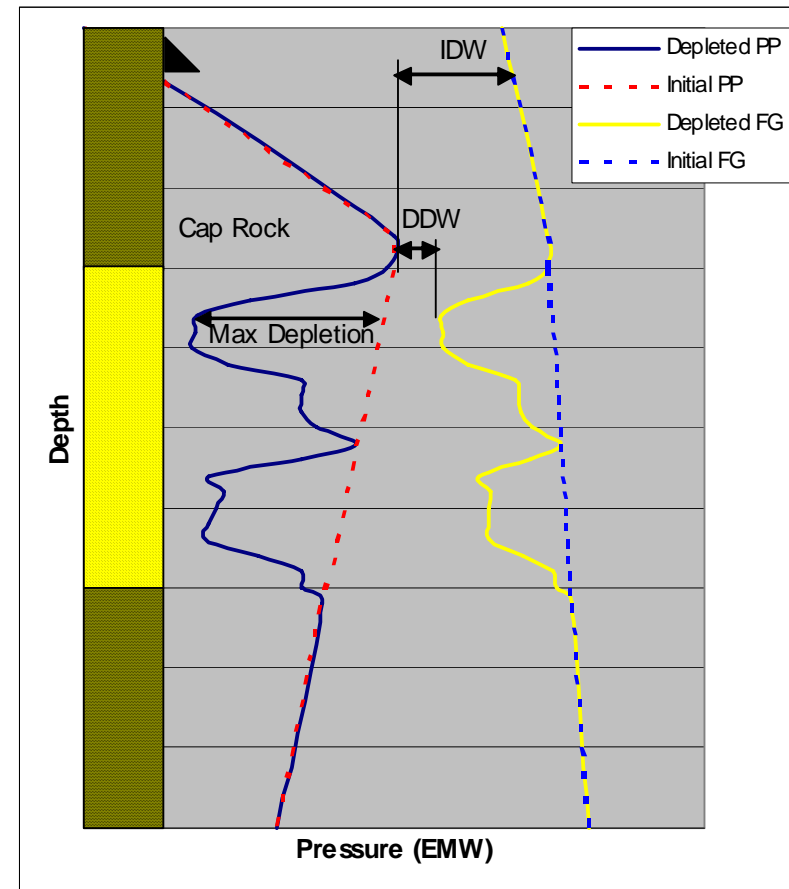
Initial/max. reservoir pore pressure (PP)

## During production:

Reservoir pore pressure decreases over time

## Reduction in fracture gradient (FG):

With pore pressure depletion there is a reduction in the fracture gradient (minimum horizontal stress) by a proportion of the pore pressure depletion – difficult to predict



IDW: Initial Drilling Window

DDW: Depleted Drilling Window

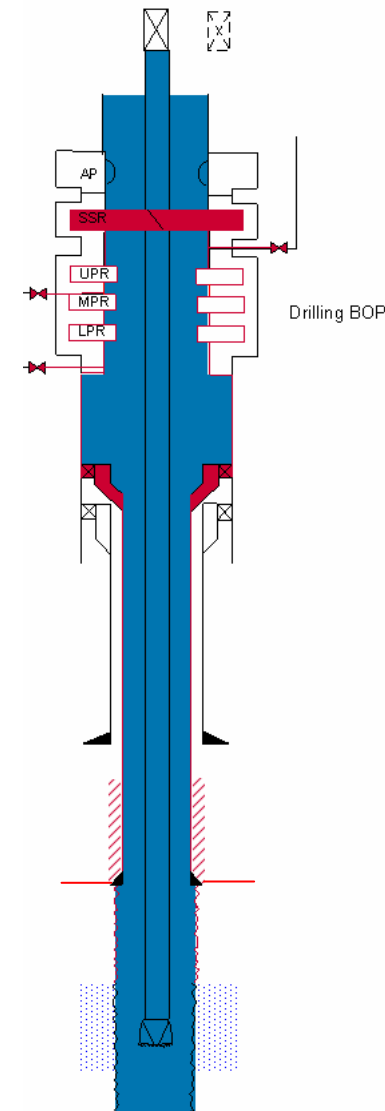
# Conventional drilling

## – Barriers and requirements

- **Primary barrier element:**
  - Fluid column
- **Secondary barrier elements:**
  - Formation integrity (kick margin)
  - Casing/cement and casing
  - WH/seal assembly
  - HP riser
  - BOP (shear ram in its ultimate stage)

- **Requirement to overbalance in NORSOK D-010**

*“The hydrostatic pressure shall at all times be equal to the **estimated or measured pore/reservoir pressure** plus a defined safety margin”*



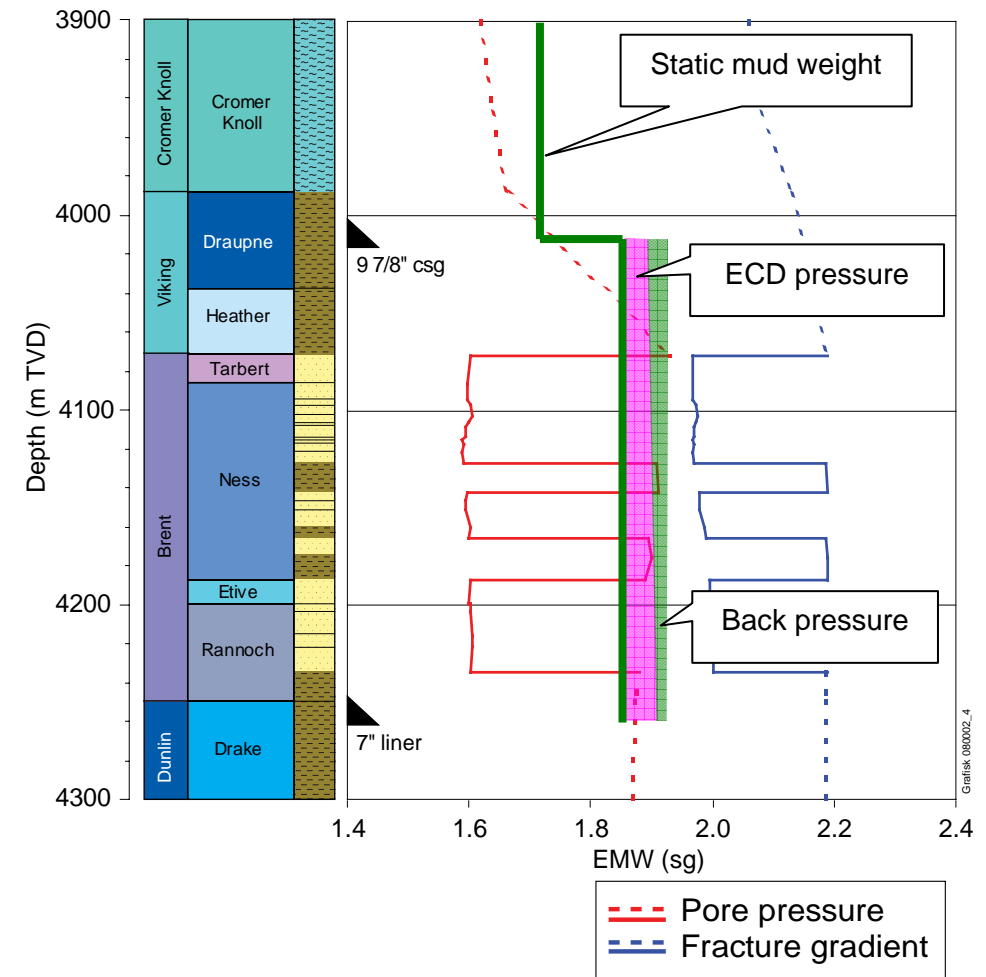
## Conventional drilling vs. MPD

- Drilling conventional provides a drilling window that can handle maximum estimated/measured pore pressure and minimum fracture gradient under **static conditions** (in overbalance with mud weight only)

Conventional:  $BHP = MW > \text{Overbalance}$

Conv. w/ CCS:  $BHP = MW + ECD > \text{Overbalance}$

MPD:  $BHP = MW + ECD + BP > \text{Overbalance}$



## WELL BARRIER SCHEMATIC

Drilling and tripping of MPD work string in UB fluid

# MPD – Barriers

### Primary barrier elements:

- Fluid column
- RCD, choke system, DP, NRVs
- All elements in secondary barrier

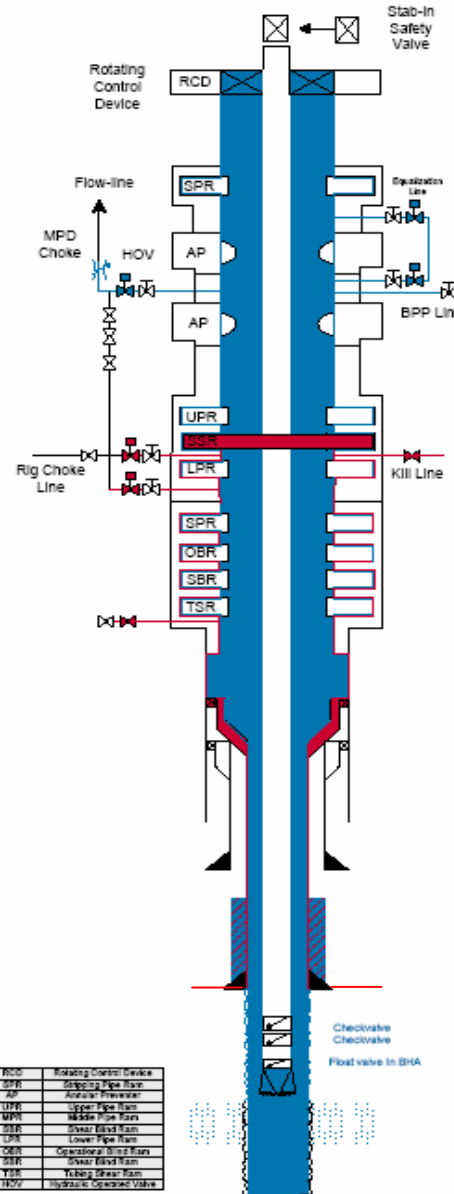
### Secondary barrier elements:

- Formation integrity (kick margin)
- Casing, casing/cement,
- WH/seal assembly
- HP riser
- BOP

### Common elements (in primary and secondary barrier):

All elements in secondary barrier envelope

**One barrier failure = Well control situation!**



RCD	Rotating Control Device
SPR	Stripping Pipe Ram
AP	Annular Preventer
UPR	Upper Pipe Ram
MPR	Middle Pipe Ram
LPR	Lower Pipe Ram
OBR	Operational BOP Ram
SBR	Shear BOP Ram
TSR	Tyler Shear Ram
HOV	Hydraulic Operated Valve

Well data	
Installation:	Gullfaks C
Well no:	C-01A
Well type:	Oil producer
Revision no:	2
Date:	12Nov 08
Prepared:	Alan Robertson
Verified:	Colin Munro

Well barrier elements	Ref. WBEAC tables	Verification of barrier elements
<b>PRIMARY</b>		
1. Fluid column	1	
2. Casing cement	22	Common WBE
3. Casing	2	Common WBE
4. Wellhead	5	Common WBE
5. High pressure riser	26	Common WBE
6. Drilling BOP (Body)	4	Common WBE
7. Rotating control device	48	
8. Drilling non-return valves	50	
9. Drill string or completion string	3	Above NRV.
	25	
10. UBO/MPD choke system	55	The flowline shall have two valves, one of which shall be remotely hydraulically operated valve (HOV) and fall 'as is'.
11. MPO Stripping Annular & Rams (Body)	NA	
<b>SECONDARY</b>		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	
4. High pressure riser	26	
5. Drilling BOP	4	Shear seal ram.
6. Safety Head & Rams below Drilling BOPs (Body)	NA	Additional Shear ram Capability

#### Notes:

1. The well control configuration described is for rig-up on installations with a surface drilling BOP.
2. The work string refers to drill string (illustrated) or completion string.
3. Stab-in safety valve is readily available on the drill floor at all time with relevant connections.
4. For common WBEs, a risk analysis shall be performed and risk reducing/mitigation measures applied to reduce the risk as low as reasonable practicable.

Disp. no.	Comment
well integrity issues	
70031	

## Challenges

- Drilling overburden and into depleted reservoir in same section
  - Not sufficient drilling window
  - No flow potential in overburden
    - Conventional
    - Dispensation to PSA – document no flow potential
    - Pore pressure plot not adjusted (in the following drilling program)
  - Flow potential in overburden
    - MPD
- Uncertainties in pressure prognosis
  - Presence of initial pore pressure
  - Grade of depletion and how the depletion influences the fracture pressure

## Challenges – cont.

- Homogeneous vs. heterogeneous reservoir
  - Homogeneous – same depletion all over (“sandkasse” as Statfjord)
  - Heterogeneous – possible depleted zones and zones with initial pore pressure (KvB)
- Drilling in depleted reservoirs – fairly “young” challenge
  - Lack of criteria and requirements in the industry
  - Limited experience and competence – for instance with MPD



## New requirements in StatoilHydro

### AF § 76 og IF § 47

**Should** fulfil requirements in Norsok D-010

### Norsok D-010

The hydrostatic pressure shall at all times be equal to the estimated or measured pore/reservoir pressure, plus a defined safety margin (e.g. riser margin, trip margin).

### StatoilHydro – from 01.04.09:

The hydrostatic pressure shall at all times be equal to the estimated or measured pore/reservoir pressure, plus a defined safety margin (e.g. riser margin, trip margin) of **minimum** 0.02 sg during drilling and 10 bar during completion/interventions.

## New requirements in StatoilHydro

### Drilling conventional: Static BHP < Initial pore pressure in reservoir

It is acceptable to drill conventional in depleted reservoirs with the static BHP below the initial pore pressure (or injection pressure if higher) when the following criteria are met:

- 1) Documented knowledge of area. If this is not met, the well bore pressure cannot be lowered below initial pore pressure until pore pressure is verified after drilling through the formation.
- 2) The initial pore pressure shall be less than the dynamic BHP.

3) Risk assessment must conclude that risk to meet any intervals with initial pore pressure is highly unlikely; should be at a probability level from zero to one\* percent maximum, considering for instance:

- a) probability for presence of sand
- b) probability for permeability (> 0,1 mDarcy)
- c) if a) and b), probability for initial pore pressure.

\*: If good pore pressure correlation can be documented historically, a probability level from zero to five percent maximum could be acceptable

- 4) Risk assessment must conclude that risk for loss is significantly higher than risk for gain.
- 5) All well barrier elements must be documented in well barrier schematic (WBS).
- 6) Consider to verify the cement behind the production casing/liner with a cement bond log.
- 7) The minimum horizontal stress should be higher than the initial pore pressure.
- 8) The static BHP should exceed the collapse pressure of the formation.
- 9) Operational compensating measures must be defined. Examples of this can be more frequent flow checks, circulating bottoms up, pump of tests, finger print of flowback on connections etc.

There is no need to apply to the PSA provided the pore pressure curve in the drilling program is below the planned mud weight to be used.

## New requirements in StatoilHydro

### Drilling conventional: Static BHP < Pore pressure in impermeable fm/overburden

Minimum criteria for applying to the PSA to drill through formations with no flow potential in an underbalanced (mud weight below pore pressure curve), using conventional drilling equipment is as follows:

- 1) Documented knowledge of area. If this is not met, the well bore pressure cannot be lowered below pore pressure until the lack of flow potential is verified after drilling through the formation.
- 2) The dynamic BHP shall be higher than the pore pressure.
- 3) Risk assessment must conclude that risk to meet any intervals with flow potential is highly unlikely; should be at a probability level from zero to one\* percent maximum, considering for instance:
  - a) probability for presence of sand
  - b) probability for permeability (> 0,1 mDarcy)
  - c) if a) and b), probability for pore pressure > mud weight.

\*: If good formation correlation can be documented historically, a probability level from zero to five percent maximum could be acceptable.
- 4) Risk assessment must conclude that risk drilling overbalanced is higher than drilling underbalanced.
- 5) All the well barrier elements must be documented in well barrier schematic (WBS).
- 6) The static BHP should exceed the collapse pressure of the formation.
- 7) Operational compensating measures must be defined. Examples of this can be more frequent flow checks, circulating bottoms up, pump of tests, fingerprint of flowback on connections etc.

# New requirements in StatoilHydro UBO and MPO (Underbalanced – and managed pressure drilling and completion operations)

- New requirements in Well Integrity Manual
- Based on Norsok D-010 – but will differ between UBO and MPO
- Defined WBEAC for UBO/MPO choke system

1.1 Table 55 – UBO/MPO choke system

Features	Acceptance criteria
<b>A. Description</b>	The MPO/UBO choke manifold is a control device for the purpose of controlling the pressure and fluid flow to surface from the well. It consists of flow line from the well, including two isolation valves, and a minimum of two parallel chokes with suitable isolation valves for maintenance. All fluid returns from well will be routed through the choke manifold. At least one of the isolation valves shall be remotely operated.
<b>B. Function</b>	Its function is to control the wellhead pressure within predefined limits and reduce wellhead pressure to atmospheric or to a separator inlet pressure.
<b>C. Design, construction and selection</b>	<ol style="list-style-type: none"> <li>1. The selected choke manifold shall be fit for purpose to operate as designed within the expected operating pressure envelope.</li> <li>2. Design should be such that change out of one choke valve can be done with pressure control of the annulus on the other choke.</li> <li>3. The selected choke manifold shall have a pressure rating greater than or equal to the maximum expected UBO/MPO well head pressure.</li> <li>4. The elements of the selected choke components shall be compatible with the operating fluid environment (liquid, gas, drill cuttings and multiphase) expected. The system must be able to handle the rates of the returning fluids and solids.</li> <li>5. The element of the selected choke manifold shall be compatible with the expected operating temperature envelope.</li> <li>6. The choke manifold shall by design be capable of withstanding vibration and shock loads without failing.</li> <li>7. Choke size shall be selected to optimize well head pressure control and minimize wear.</li> <li>8. All metallic materials, which come in contact with well fluids, shall meet the requirements of ISO 15156-1 for sour service.</li> <li>9. Choke control (manual or automatic) shall be fit for purpose.</li> <li>10. The fail safe remotely operated valve shall be fit for purpose to be able to isolate the rest of the surface system in case of an emergency and be designed to the same pressure as the RCD and failsafe as is.</li> </ol>
<b>D. Initial test and verification</b>	<ol style="list-style-type: none"> <li>1. The choke manifold elements shall be subject to documented low and high pressure tests, prior to delivery, after initial installation and after repair or replacement. NOTE: The choke valves are not designed to hold pressure and will not be pressure tested.</li> <li>2. It shall be defined acceptance criteria when using an automatic choke control system. Limits shall be stated and choke control system must be verified to be able to stay within these limits before the operation is started.</li> <li>3. Integrated function testing will be carried out after initial installation and will include the choke control system(s).</li> <li>4. Material certificates for the choke manifold and components shall be available.</li> </ol>
<b>E. Use</b>	Choke sizes shall be optimized to reflect expected operating conditions and requirements. Choke swapping in the event of a blockage will be automated or controlled through procedure.
<b>F. Monitoring</b>	<ol style="list-style-type: none"> <li>1. Corrosion and erosion programs shall be developed to reflect the operating conditions</li> <li>2. Periodic visual inspection for external leaks.</li> <li>3. Upstream choke pressures shall be monitored and controlled by independent and redundant pressure monitoring systems.</li> <li>4. Remote indication of choke position shall be monitored.</li> <li>5. Periodic leak- and functional test, minimum each 14 d.</li> </ol>
<b>G. Failure modes</b>	<p>Potential failure modes shall be identified through a recognized risk analysis method. Local and overall effects shall be described and risk reducing control methods implemented. The cause of failure shall include as a minimum:</p> <ol style="list-style-type: none"> <li>1) corrosion, 2) erosion, 3) mechanical failures, 4) plugging/blocking, 5) instrument failure, 6) choke control system if using automatic choke control, 7) loss of mud pump/power loss.</li> </ol>

## A “fresh” example....

... from an exploration well

- Applied for dispensation to drill 5 points in underbalance
- Dispensation was **not** recommended
  - Last minute dispensation (even though planning exploration wells is a maturation process)
  - Was not able to not quantify the probability of the high pore pressure case (other than it was low....)
  - Even though risk for loss is higher than risk for kick
- Always uncertainties in the pressure prognosis in exploration/wildcat drilling

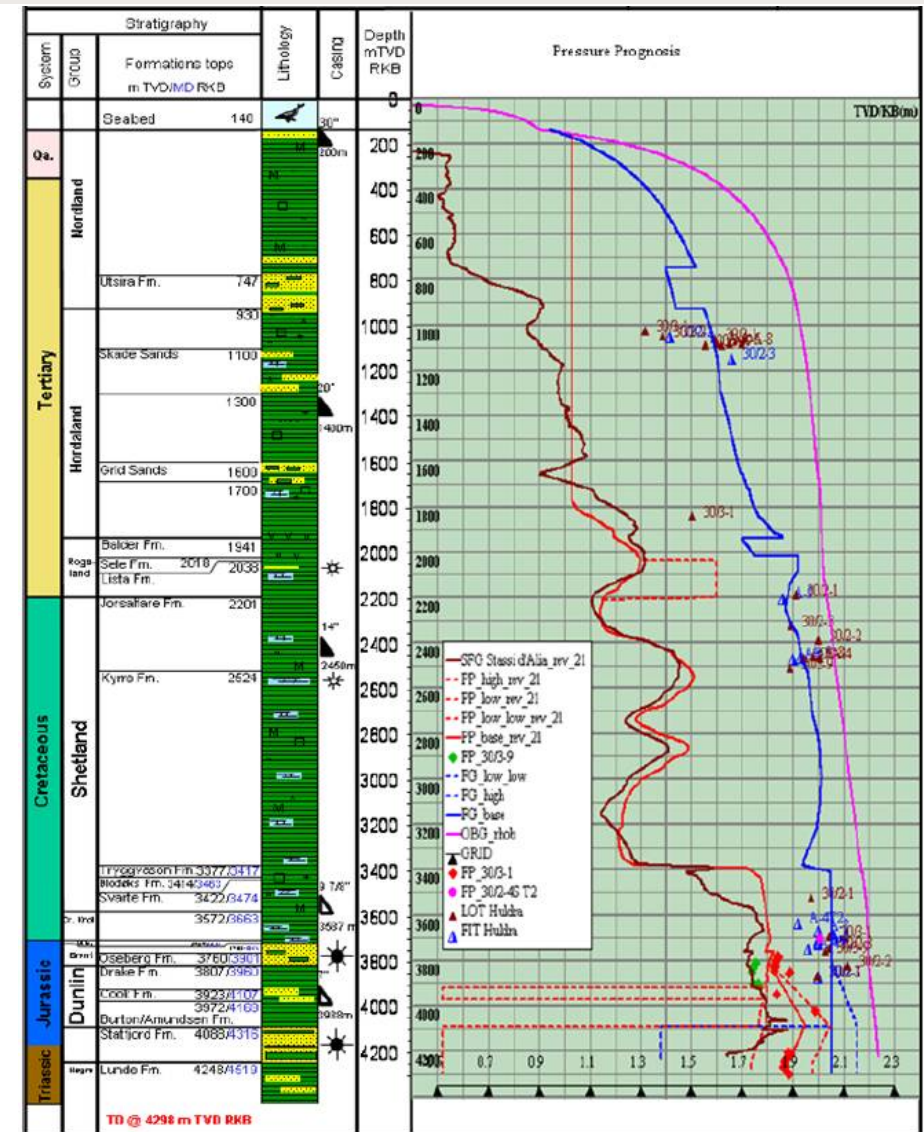


Figure 6-1: Pressure plot



## Summary

- Aware of the challenges drilling in depleted reservoirs
  - An internal multidisciplinary workshop related to this topic was arranged in May 08
  - Consequently new requirements will be submitted from 01.04.09
    - Conventional drilling in overburden
    - Conventional drilling in depleted reservoir
    - MPD in overburden and depleted reservoir
  - Need probability data of pore pressure prognosis
    - To define and improve the frames
  - Still need for better understanding and more experience with MPD – thus important to take one step at the time

