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Sand Control Selection in HPHT Reservoirs

Master's Thesis by
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Abstract

High Pressure High Temperature (HPHT) reservoirs have shown to have great potential of oil and gas reserves through industrial experience. Norwegian Continental Shelf has such good potential HPHT reservoirs. But, HPHT reservoirs present their own challenges when drilling and completing wells in such reservoirs especially when they have the potential for Sand Production. It is necessary to design proper sand control mechanism to utilize the full potential of the reservoir. Lack of planning and information may lead to loss of production and unnecessary remedial work which will make the potential reservoir economically unviable.

This thesis presents the study of Sand Control Selection in HPHT High Rate Gas wells drilled in Total's Martin Linge Field, main focus being on evaluation of use of ESS (Expandable Sand Screens). Martin Linge Field is the first field where ESS screens have been installed in HPHT reservoir and this study presents both theoretically and by the use of calculations if ESS is potentially a successful sand control strategy in HPHT fields, especially in HPHT high rate gas wells. Sand control completion design and production potential after the completion has been discussed extensively. Currently drilled gas wells completed with ESS in the field have known to show less potential for production than expected. The main objective here is to study the influence of different sand control methods on the productivity of wells by utilizing calculations and simulations and comparing those with the currently selected sand control completion by Total. Further, trying to identify the potential problems with current well completion and suggestion of alternative sand control completion procedure that might have been more productive. This study can then be used for future wells on Martin Linge and can also be useful in similar HPHT High Rate Gas wells.

The effect of influence of Sand Control Selection on the skin of the wellbore has been analyzed. Skin is known to directly show the influence of productivity on the wells. This analysis will help in selection and design of appropriate sand control selection in HPHT wells such that low skin can be obtained which will have a good effect on the productivity of the wells. Discussion has been done at the end of the report suggesting the viable sand control technique that can be successfully implemented in HPHT fields and future of ESS completion technique in HPHT fields.

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Author

Nachiket Jadhav.

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List of Acronyms

HPHT High Pressure High Temperature

BHT Bottom Hole Temperature

NCS Norwegian Continental Shelf

SAS Stand-alone Screen

ESS Expandable Sand Screens

OHGP Open Hole Gravel Pack

ML Martin Linge

RDiF Reservior drill-in Fluid

SRiF Screen run-in Fluid

Cs/k Cesium Formate

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1. Introduction

On a global basis, sandstone formation reservoirs are the most recurrent reservoir category in oil and gas reservoirs. A sandstone reservoir is by definition a reservoir from where petroleum can be extracted from sandstone by known technology. Considering the matrix and formation grain properties, they can range from consolidated to highly unconsolidated. Sand production is a consequence of the lack or ineffectiveness of cementing material between sand grains of the formation. Worldwide, sand production is a matter that has caused the petroleum industry to spend millions of dollars cleaning sand out of the wells and repairing problems associated to sand production. A further consequence of sand production is the fact that petroleum industry has lost revenue due to limited production rates. [1]

In recent years the knowlegde that high pressure high temperature (HPHT) reservoirs have prodigious potential of oil and gas reserves has been aquired through industrial experience. A relevant example of where several of these reservoirs are located is the Norwegian Continental Shelf. HPHT reservoirs present their own challenges when drilling and completing wells, especially when they have the potential for Sand Production. In the United Kingdom and Norway, a high-pressure high-temperature (HPHT) well is defined as follows-

Undisturbed BHT (Bottom Hole Temperature) at the prospective reservoir depth is greater than 149 degrees C (300 degrees F) and the maximum anticipated pore pressure exceeds 690 bar (10,000psi) i.e 0.8 psi/ft (18kPa/m). For such wells, pressure control equipment with a rated working pressure in excess of 10,000 psi is required. [3]

This thesis offers a study of Sand Control Selection with the main focus being on evaluation of use of ESS (Expandable Sand Screens) in HPHT High Rate Gas wells drilled in Total's Martin Linge Field. The Martin Linge Field is the first field where ESS screens have been installed in a HPHT reservoir and this study presents both theoretically and by the use of calculations if ESS is potentially a successful sand control strategy in HPHT fields, especially in HPHT high rate gas wells. Analysis and discussion of the effect on wellbore skin due to selection of particular sand control solution will be carried out. The analysis and discussion will show the effect that the usage of ESS will have on well production. By comparing past experiences in sand control strategies used in similar HPHT High Rate Gas wells on NCS through further extensive discussion an assumption as to which sand control strategy is best suited in HPHT reservoirs will presented. The study carried out in this thesis will further be used for future wells on Martin Linge and can also be useful in similar HPHT High Rate Gas wells.

Finally, a summary and a conclusive presumption from the discussions will be presented, which will give a respectable indication of the efficiency of ESS completion in HPHT high rate gas wells in addition to which sand control strategy is resourceful in the abovementioned reservoirs. A number of suggestions will also be presented for future sand control selection in HPHT high rate gas wells.

2. HPHT Sand Control

This section provides extensive literature survey. The aforementioned can be utilized as an adequate reference for HPHT sand control selection due to limited literature availability focusing solely on HPHT sand control. The main focus of this section is kept on sand control selection in HPHT high rate gas wells. Sand control and sand control selection in normal pressure/temperature reservoirs can be found in many literatures like Bellarby (2009), Economides (1993), and Allen (1989).

2.1 Sandstone Reservoirs

The focus of this section will be on Sandstone reservoirs although sand control is needed in other formations as well, but in sandstone reservoirs sand production is more prevailing and a big concern in oil and gas production. Sand complications transpire in both younger and older tertiary sediments but are most probable to occur in the younger sediments. In older tertiary sediments the local earth pressures or production practices could lead to sand production due to unstable circumstances. [1]

Cementation between the grains of sand causes the grains to become stable. Despite the aforementioned claim, if the forces from fluid flowing through the sand become vaster than the cementing can withstand, grains of sand will approach into the wellbore along with the fluid. Influx of water may impair the stability of the formation. If the inflowing water has a different chemical composition than the prevailing water, it can disperse the cementation holding sand particles in place. In HPHT formations the aforementioned effect will be more recurrent. [1]

The movement of sand particles can negatively affect the producing system. Production can come to an end if the crushed sand grains get stuck in voids and pore throats. This will cause a loss of permeability due to the formation becoming plugged. This is called formation damage, which has detrimental effect on well productivity. [1]

Sand production is a threat to equipment. If sand grains transported in fluid are moving at high velocity in wells with high gas rate, they are capable of doing great damage to subsurface equipment, for instance hot spotting on sand screen, failure of sand screen, wearing through or parting tubing and tubing accessories. The sand grains can also cause impairment if the fluid velocity is low, in the form of plugging tubing. Surface facilities can also be affected negatively by sand. Separators can become inefficient due to decrease of volume available to the liquid and vapor phases if large amounts of sand settle in the separators, in which can cause severe loss of production. [1,2]

Reservoir permeability is reduced by formation damage. Downhole damage deteriorates the performance of the well and surface damage is a peril for the safety, as well as reducing surface installation efficiency. [1]

The production of sand is an expensive problem. The aim of sand control is to stop sand production while still sustaining the maximum achievable well productivity. Sand control has its advantages. There is a reduced expenditure of changing eroded equipment, determining if sand will pose a problem or not, as well as reduced cost of surface facilities to measure, separate and dispose sand. The possibility of casing fill and collapsed casing is reduced and reduced risk of blowout due to eroded surface lines and valves. Although sand control has advantages, it possesses the hazard of reduced well productivity and difficulties shutting off water or workover the wells. [1,2]

2.2 Challenges with HPHT Sand Control

This section presents an insight on challenges with HPHT sand control compared to conventional methods. The two very important points to be considered before designing HPHT wells are [3]

1. Most HPHT reservoirs are deeper than the normal pressure/temperature reservoirs. It is evident that as one goes deeper the margin between formation pore pressure and fracture pressure becomes short. So, there is usually a very small margin between the fracture gradient and pore pressure as we go deeper and near the reservoir section. This difference is critical in the design of the well since narrow margins might possess issues with well control.

2. Lost circulation is the major problem in HPHT wells as they have usually high ECD's (Effective Circulating Density) and it becomes difficult to control a well followed by a continuous loss/gain cycle.

Below are listed some of the consideration that needs attention when designing an HPHT well[3]

Thermal effects on fracture gradient [11]
Due to high temperature thermal stresses can be induced around the borehole wall when drilling a HPHT well. High temperature can have significant effect on stability of the wellbore. When drilling cool drilling mud comes in contact with the high temperature formation, cooling or heating by few degree celsius can induce tensile/compressive stresses around the borehole wall and can make the nearby formation brittle which can lead to low fracture initiation pressure than expected. Due to these reason it is essential to consider thermal stresses that can be induced on formation in HPHT wells and safety margin should be included between ECD and fracture gradient.

Breathing or ballooning [3]
Ballooning refers to the ability of the open hole section to stretch and expand under the effect of ECD. This effect is detrimental in HPHT wells. In short the mechanism is – when pump are on the micro fractures in the formation can take some mud and when pumps are off, micro fractures will close and give mud back. In this process small volume of mud can be mistaken as a small kick. So, it is essential to take into consideration the effect of breathing or ballooning in HPHT wells.

Pipe speeds [3]
Surging and swabbing can be induced when running-in hole or pulling-out of hole. In HPHT wells it is critical to control pipe speeds due to narrow margin between pore and fracture pressure as mentioned above, to avoid critical swabbing which might result into kick or surging which can induce fractures i.e. loss circulation.

Pressure to break gel [3]
In deep wells high pressures can be induced on formation if the mud circulation is broken too quickly. In HPHT wells, it is essential to know the pressure required to break the gel strength [4] of the mud to avoid ECD to exceed beyond fracture pressure which can lead to loss circulation.

Casing design considerations [3]
HPHT reservoirs contains oil or gas condensates at extremely high pressures and temperature, so it is necessary to consider this effects on the casing design when selecting the grades/weights since they should withstand high temperature/pressure during lifetime of the well. If casing fails during the lifetime of the well, there can be severe consequences with regards to safety of rig and personnel. High temperatures can cause thermal expansion of casings leading to collapse. Another risk known to occur due to high temperature is intermediate or production casings collapse as these casings get affected by hot producing fluids. [12] For detailed design considerations for casings, reader is advised to refer to [13].

Barite sag
Sag is defined as the settling of barite or other heavy weighting materials towards the low side of the wellbore causing significant variations in mud density [3]. This has been one of the major concern when drilling HPHT wells, since plenty amount of barite particles are added to the mud to make it heavy to provide overbalance against high pressure formations. If barite sagging occurs it can have several consequences as listed below [3]

- Lost circulation.
- Well control problems.
- ECD fluctuations.
- Torque and drag.
- Logging problems.

• Poor cement jobs.

Following primary reasons are considered to be the reason for excessive barite sagging

• Hole Angle: Barite sagging is mostly observed in wells having angles higher than 75 degrees, with the effect being most critical in 60-75 degree angle wells [14].

• Low Annular Velocities: Barite sagging can increase with low annular velocities [14].

• Time between trips: Sagging increases with time, more stationary time between tripping can lead to excessive sagging. [14]

• Drillpipe Rotation: Barite sagging is more sensitive to pipe rotation than low annular velocities. [14]

• Eccentricity: Eccentricity can increase barite sagging as it results in low annular velocity. [14]

Several literatures [14, 15] have been published to avoid and prevent barite sagging related to some above mentioned points in HPHT wells.

Trapped annular pressure [3]
Trapped annular pressure has shown to serious issues with HPHT wells where produced fluids heat the casing and the trapped fluids in the annulus between intermediate and production casing causes fluid expansion which can over-stress casing/tubing resulting into deformation of casing strings.[16, 17] It is therefore essential to bleed off the this trapped pressure to avoid severe damage to the casing. [18]

In this section some of the important challenges with HPHT wells were presented. But apart from this there are more challenges that should be considered in HPHT fields. All literature will not be presented here, since the aim of this thesis is not to present extensive literature. But, reader is advised to refer to publications by Shardravan et. el. [16] and Zeringue [37] where detailed HPHT challenges have been presented.

2.3 Sand Control

The production of sand in oil and gas wells is expensive and everything possible should be done to successfully control the formation sand, but what is meant by "successful" control? The goal of any sand control treatment must be to stop sand production while maintaining or maximizing fluid production. [1]

It is not enough to simply stop sand production as this is easily done by shutting the well in or cementing off the producing interval. These two solutions, however, also stop fluid production. The total success or failure of a sand control treatment must be measured against three related criteria:

• Stop sand movement and production of sand.
• Maintain maximum well productivity.
• Payout the treatment costs within a reasonable time.

All three of these criteria must be met for a sand control treatment to be considered truly successful, and each item should be considered when designing, performing, and evaluating a sand control treatment. If there is an indication of potential sand production problems in a field, a decision may be made before development to gravel pack every well as insurance against sand production. [1]

Pros and Cons of Sand Control
Several advantages and disadvantages of sand control have been listed below by referring to several literatures like [1, 2]

Advantages:
• Reduced cost of surface facilities to measure, separate, and dispose of sand.
• Reduced cost of changing eroded chokes, subsurface safety valves, etc.
• Reduced possibility of casing fill and collapsed casing.
• Less risk of blowout due to eroded surface lines and valves.
• Reduced cost of trying to determine if sand will or will not cause problems.

Disadvantages:
• Possibility of reduced well productivities.
• More difficult to shut off water or workover the wells.

2.4 Sand Control Methods

This section decribes several sand control methods currently in practice in the oil and gas industry. Only brief description is provided to have an idea of different sand control methods.

There are two main methods of sand control. Mechanically excluding the sand by setting up a screen barrier surrounded by fine gravel to the sand movement, which still permits for the passage of reservoir fluids. The second method is chemically consolidating the sand grains by injecting chemicals into the formation, this makes it possible to cement the grains of sand together, thus providing strength. Both of the aforementioned methods, aims to counteract movement of sand while maintaining permeability. [1]

Here we try to list some mechanical sand control methods, since those are the ones we will be focusing on for our main part of the thesis. The below mentioned methods are for open hole sand completions. For other sand control methods reader is advised to refer more literature if interested. Here, we list three important open hole sand control completion methods that have been discussed in the main part of the thesis.

- Stand-alone Screens (SAS)
- Open Hole Gravel Pack (OHGP)
- Expandable Sand Screens (ESS)

Stand-alone Screens (SAS)

Stand-alone screens (SAS) are used widely in the industry due to their simplicity in installation and cost effectiveness. SAS are generally preferred solution in highly-consolidated formations, since SAS completion leaves annular space between borehole and the screen. [19] If sand production occurs at high rate this might result into erosion of screen and further failure of screen can lead to sand production and in worst case abandonment of the well. SAS screen can be of different types like wire-wrapped, pre-packed and premium screens depending upon the size of the sand particles that needs to be stopped. [20] Figure 1 shows general configuration of SAS screen.

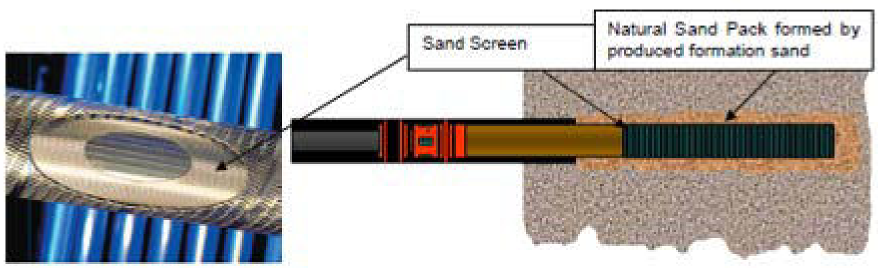

Figure 1 Sand-alone Screen Completion

Open Hole Gravel Pack (OHGP)

Open hole gravel pack (OHGP) have become a very common technique for sand control completion. The basic technique is to place gravels or sand that is larger than the average formation sand grain in the annulus between borehole and the screen. This technique is usually used where high fines production will be expected. This gravel pack creates a natural sand pack that provides the support to the formation and retains most of the formation sand [2]. There are different techniques used for gravel placement like circulating packs, alternate path gravel packs and high-rate water pack (HRWP). [1] Figure 2 shows general configuration of OHGP placement.

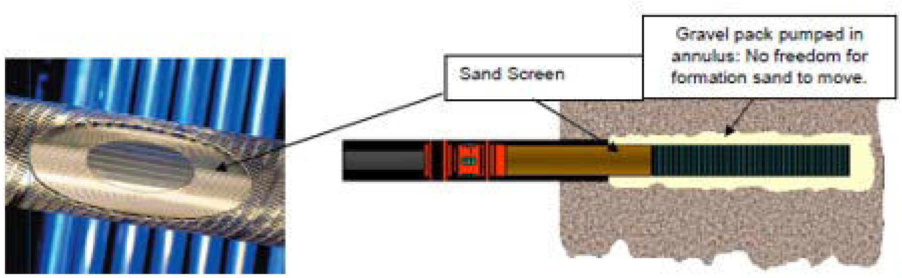

Figure 2 OHGP Completion

Expandable Sand Screens (ESS)

Expandable sand screens are relatively new technology in the industry and its use has been increasing due to its simplicity of installation and low installation cost than OHGP. ESS eliminates the annulus unlike the SAS screens. The main difference with OHGP is that the filtering media is a woven mesh instead of calibrated gravel. Other notable difference is that expandable screens do not involve pumping different fluids, which simplifies operations and reduces the risk related to fluid design. Expandable screens have the simplicity of SAS, while allowing a more efficient reservoir wellbore interface by eliminating the screen to hole annulus. ESS can be expanded in two ways – compliant and non-compliant depending upon the application. Compliantly expanded system completely eliminated the annular gap, while non-compliant system leaves a small annular gap between screen and borehole wall. Different techniques are used to expand ESS – fixed cone with weight applied by the drill pipe, using fixed roller (non-compliant) and using pistons to actuate the rollers against the screens (compliant). For detailed information on different mechanism for ESS, reader can refer to [1] and some publications like [21, 22, 23] to mention a few. Figure 3 shows general configuration of ESS placement in an open hole.

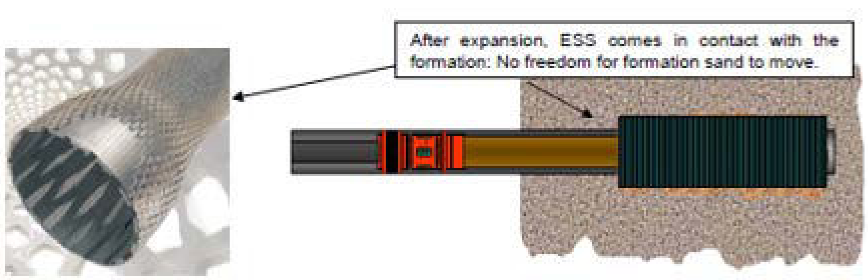

Figure 3 ESS Completion

2.5 HPHT Fluid Systems

It is very essential that efficient drilling fluid system is selected for HPHT wells. Conventional drilling fluids have limitations that lead to high frictional pressure loss during circulation and high ECDs in narrow drilling windows. [24] The most important drilling fluid selection is when drilling the reservoir section where high pressure and temperature will be encountered. Over the years different formulations of drilling fluids for HPHT purpose have been proposed. [25]. HPHT wells should be stable under HPHT condition and their rheology should be such that it minimizes ECD. Following are the three drilling fluid systems commonly in use in HPHT wells. Only brief description is provided here.

Invert Emulsion HPHT Oil Based Mud (OBM) [26]

The fluid system is based on paraffin as the base oil and barite as the weighting material. It gives low viscosity and reduces the impact of ECD, has known to shown excellent sagging stability and bridging capacity in HPHT wells.

Invert Emulsion HPHT OBM with Micronized Barite Slurries (MBS) [26, 27]
The fluid system consists of specially treated weighting material for improved performance. Barite is generally grounded to micron size of 1 to 3µm and coated to prevent interaction with particles. This allows to eliminate the barite sagging effectively. Due to small particle size it has known to plug the screens.

Cesium/Potassium Formate Mud (Cs/K) [26, 28]
This fluid system is based on clear brine containing Cesium and Potassium Formate. This system has gained worldwide popularity due to their excellent performance. It has been known to be used extensively on NCS showing excellent results in well productivity. 99068Only disadvantage of this mud is that the cost per unit volume of this system is much higher than other fluid systems.

In later section, we identify the advantages and disadvantages of fluid systems used on NCS.

3. Martin Linge Sand Control Selection

3.1 Introduction [10]

MARTIN LINGE (ML) / Hild (formerly known as Hild) field (Figure 4) is one of the major un-developed gas discoveries in the North Sea. MARTIN LINGE's discovery well was drilled in 1975 with a further 11 exploration wells drilled between 1975 and 1985. MARTIN LINGE Gas was proven in 1979 near the delimitation line to the UK Continental Shelf. The field consists of several faulted and segmented gas accumulations in the mid-Jurassic Brent Group.

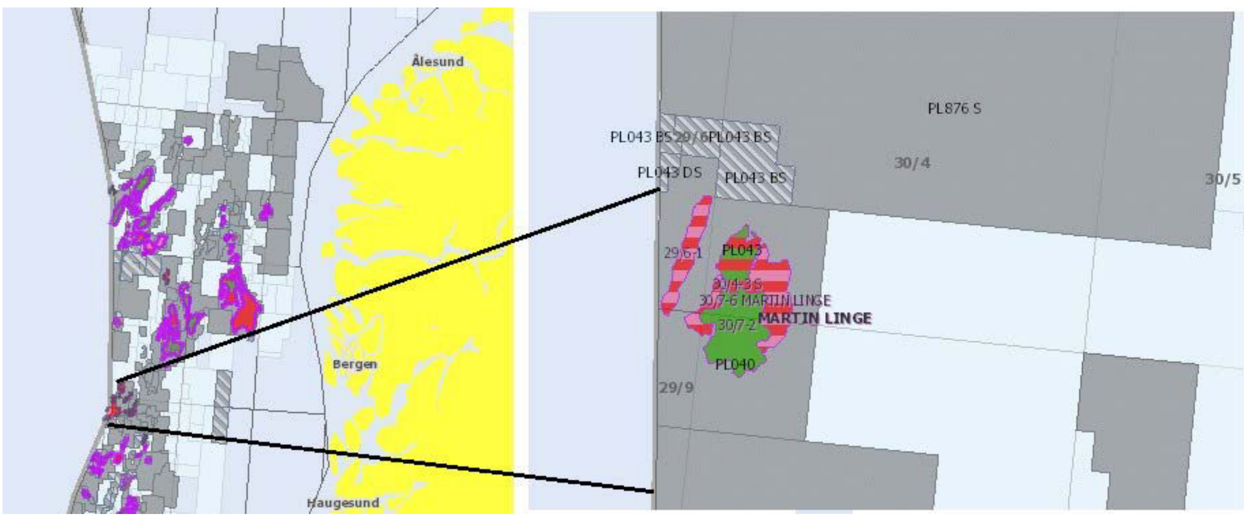

Figure 4 Norwegian Block Martin Linge Field

The Martin Linge Unit lies in close proximity to the UK border within the Norwegian blocks 29/6, 29/9, 30/4 and 30/7 in the northern North Sea and the sea depth in this area is around 120m. It contains oil discoveries in Frigg of Eocene age (1700-1850m TVDSS) and gas/condensate discoveries in the deeper Brent Jurassic reservoir (3600-4200m TVDSS). Total E&P Norge AS (51%) is operating the license with Statoil ASA (19%) and Petoro (30%) as partners.

In a regional context, the Martin Linge Unit is on the western flank of the Viking Graben. The Upper Brent high pressure gas and condensate discoveries comprise a series of strongly faulted and segmented structural traps created during the major late Jurassic rifting phase. The Martin Linge Middle Jurassic Brent reservoirs are characterized by rather layer-cake geometry with only minor facies and thickness changes laterally. Deposits have been interpreted as an eastward prograding wave-dominated delta complex with tidal influence. At the base, the Ness is fluvio-deltaic with channels and flood plain deposits. The transition to the shore face and tidal channel deposits of the Tarbert formation is marked by a major transgression with very good tidal inlet sand deposits at the top.

The main reservoir (Tarbert Fm) shows a high Net To Gross (50-95%) with good properties especially in the Martin Linge East shallowest structure with porosities between 20-30% and permeability range from a few mD to several Darcies. Reservoir quality deteriorates from Martin Linge East to Central and West with increasing depth and stronger diagenesis impact.
Martin Linge Oil (Frigg) reservoir pressure is 178bar at 1732m TVDSS, oil gravity is 21 API and permeability is 500 to 4000mD. It is being developed with 4 producer wells (Horizontal drains) and 2 potential water injector wells. Producer wells are long horizontal drains. Open Hole Stand Alone Screens is used as sand control. The base-case reserves for ML oil are 43 Mboe. Martin Linge (Brent) gas condensate and the Frigg oil will be a combined development. ML (Brent) gas condensate will be produced by natural depletion while gas lift will be used for Frigg oil production as a means of artificial lift due to low reservoir pressure, high viscosity and low GOR of the oil. No reservoir support is required for the Frigg Oil due to the strong aquifer. There is no contact/connection between the HPHT gas/condensate reservoirs in Brent formation and the Frigg oil formation.

Martin Linge field will be developed with a Well Processing Utility & Quarters (WPUQ) platform with gas-liquid separation, oil/condensate export to a floating offshore storage and offloading unit (FSO) for oil-water separation and full liquid stabilization and offshore storage and offloading of stabilized hydrocarbon liquids. Gas exports will be by means of a pipeline tied in to the FUKA system to the St.Fergus Gas Plant Terminal in Scotland. Oil exports will by offshore loading with storage provided by permanently moored Floating Storage and Offloading vessel (FSO) equipped with a water wash system. Offshore loading has been chosen due to high Total Acid Number (TAN) of the oil. The gas will be processed on the platform to comply with FUKA entry specification. The produced water will be separated on the FSO and sent back to the platform for final treatment and re-injection into the Frigg formation by means of a Produced Water Re-Injection (PWRI) well. Field facilities consisting of an integrated Process, Wells and Quarters platform (WPUQ) supported by an 8-legged steel jacket will be installed. The ML full field development includes the installation of an integrated jacket platform with a capacity for 21 slots. The base case development well program consists of 11 (+2 contingent) wells – 6 in Frigg oil and 7 in Brent gas including contingency wells. Currently no oil wells have and 4 gas wells have been completed. Drilling and completion operations are being performed with a heavy-duty jack up rig in cantilever mode.

3.2 Brent Gas Reservoir [10]

The discoveries in the ML Brent area include four separate high pressure gas condensate accumulations; ML East, ML Central, ML West and ML South with different depths, pressures and fluid properties. There are other prospects in the ML area that will be developed as shown in Figure 5 below. Additional prospects include Gunn N, Gunn S, Herja and Hervor. ML Brent area is planned with 6 (+ 1 contingent) wells - ML East (4 +1 wells), ML Central (1 well) and ML West (1 well).

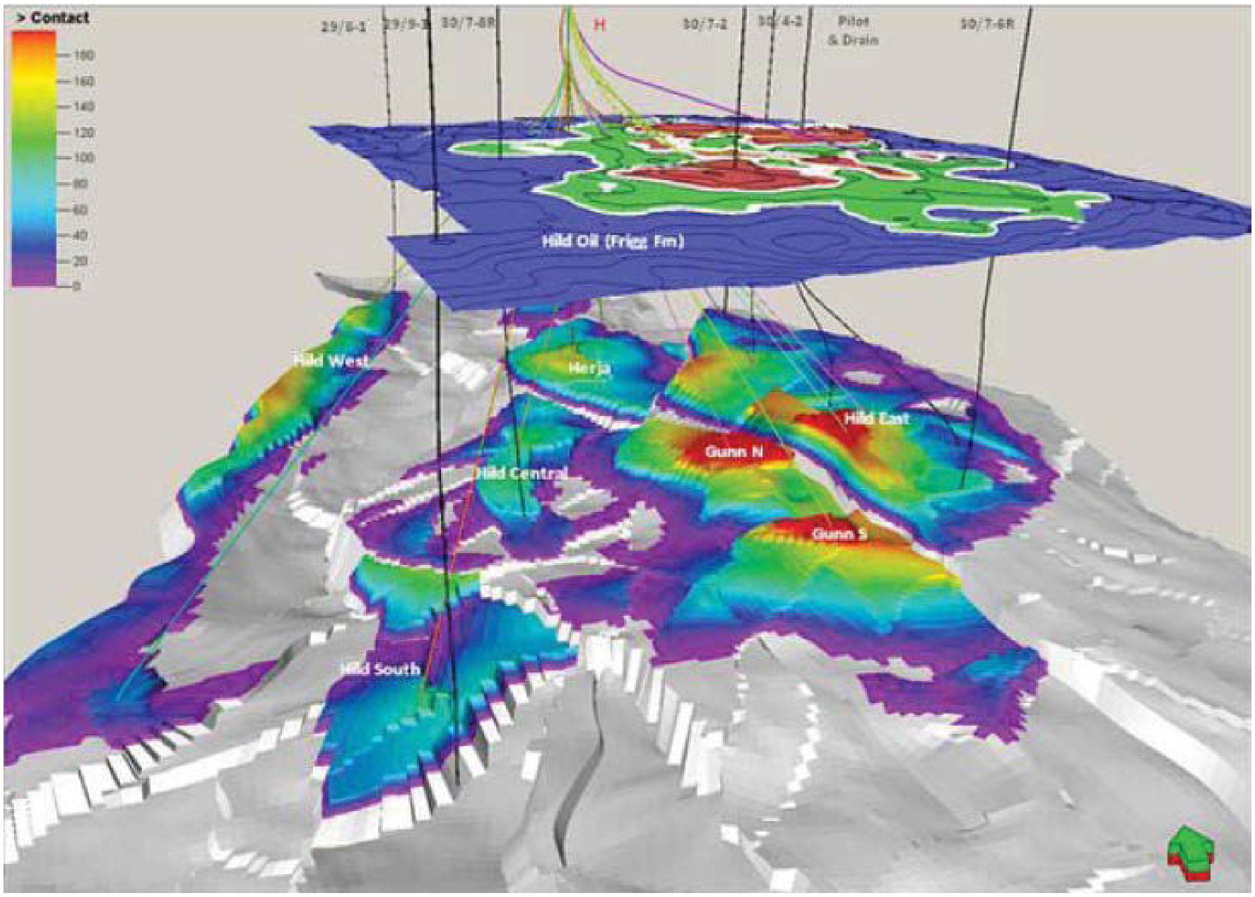

Figure 5 Martin Linge Frigg and Brent reservoirs

The interval of interest is the Jurassic Brent Group. It is subdivided into Broom, Rannoch, Etive, Etive Equivalent, Ness, Tarbert and Balta sand formations. Underlying sediments belong to the Dunlin Group, and the overlying deposits to the Heather Formation. The ML Middle Jurassic reservoirs are characterised by a rather layer-cake geometry with only minor facies and thickness changes laterally. The Brent group has a relatively constant thickness in this area between 200m up to 300m with an average of approximately 250m. The average Upper Brent thickness, consisting of Tarbert and Balta formations, is approximately 100m.

Martin Linge Gas - East

The main Brent accumulation is the ML East (MLE) structure, an Upper Brent high pressure gas and condensate accumulation, with a gas column of approximately 250m. ML East is the main horst structure of a series of faulted panels that bound the western side of the Viking Graben. The permeability of the reservoir sands ranges from a few mD up to several Darcies. The reservoir pressure is 749 bars at reference depth of 3815 m TVD/SS and the temperature is

135°C. The base-case reserves are 132 Mboe. The production mechanism is natural depletion. During the production phase pressure depletion is expected to be significant due to the fact that there is limited/no pressure support from aquifers. Two sidetracks are planned on the development wells, in addition to the contingency well, are included in order to cover for the significant uncertainties related to the structure of ML East. So far no contingency wells were needed and 4 wells have been completed successfully in the ML East block. The table 1 below gives the ML Gas East reservoir properties. Production for each well is expected for more than 15 years, therefore a robust sand control is necessary. Gas production rate is expected to be as high as 4 MMSm^3/d at the early production.

Parameter	Value
Formation names	Balta, Brent group, Tarbert 2, Tarbert 1
Reservoir rock type	Clastic (Sandstone)
Reservoir Age	Mainly Bajocian to Early Bathonian but including Late Toarcian to the east
Average Reservoir Depth	3808 meters TVDSS
Reservoir Pressure	749.1 bara
Reservoir Temperature	133 degC
Reservoir Average Porosity	Balta: 18-23%, Tarbert 1&2: 10-20%,
Reservoir Average Permeability (K)	Balta: 250 - 6000 mD, Tarbert 2: 0.5 - 50 mD, Tarbert 1: 10 - 2000 mD
Gas-Liquid Ratio (GLR)	4360 Sm^3/m^3
Dew Point Pressure @ BHT	576 bara
Condensate Density @ Reservoir Conditions	334 kg/m^3
Gas Density at Reservoir Conditions	334 kg/m^3
Condensate Viscosity @ Reservoir Conditions	0.0432 cP
Gas Gravity	0.645 SG

Table 1 Martin Linge East Reservoir Parameters

A minor description on additional ML blocks is given below, but the thesis discussion is concentrated on ML East gas wells, due to the point interest being evaluation of the performance of wells that have already been completed.

Martin Linge Gas - West

The ML West discovery is located in the western part of the Greater ML Area. The structure is an Upper Brent HP gas and condensate accumulation. Fluid analysis indicates that the gas is richer than that found in ML East. ML West is the deepest of the structures in the Greater ML Area. The permeability of the reservoir sands ranges from a 0.01 to 200 mD. The reservoir pressure is 778 bara at reference depth of 4190 m TVD/SS with a temperature of 147°C The reservoir is presently planned to be produced using a single slanted well which will be located in the central part of the ML West structure.

Martin Linge Gas - Central

The ML Central discovery is located in the central part of the Greater ML Area. The structure is an Upper Brent HP gas and condensate accumulation. Fluid analysis indicates richer gas than that found in ML East. The permeability of the reservoir sands ranges from a 0.1 to 500 mD. The reservoir pressure is 778 bara at reference depth of 4040 m TVD/SS with a temperature of 143°C.

The entire ML (Brent) gas condensate will be produced by natural depletion. The field gas treatment capacity (compressor capacity) is planned to be 9.75 MSm3/d, comprised of gas lift capacity of 1.5 MSm3/d and a gas export capacity of 8.25 MSm3/d. The production strategy is limited by the compressor performance curves. A maximum well gas rate of 4 MSm3/d has been selected to lower downhole sand erosion hazards according to the sand control feasibility studies.

3.3 Sand Control Selection [9]

The ML Brent Sand strength varies from unconsolidated to moderately consolidated. Formation failure and the subsequent onset of sand production is expected early in well life with formation failure anticipated at drawdown of between 45 - 60 bar under 0 depletion conditions. Total’s sand control feasibility studies evaluated the risk of sand production from the Balta and Tarbert sandstones encountered in the Eastern and Western panels of the ML Gas field. Based upon reservoir core material taken from wells 30/4-2 (BP 1979), 30/7-8R (Norsk-Hydro 1981), and 29/6-1 (BP 1982). It is concluded that very early sand production should be anticipated and hence the requirement for a reservoir well bore interface completion technique that contains sand control was necessary.

The figure 6 below shows the particle grain size distribution from well 30/4-D-1H well which has been used for sand control feasibility studies. The figure 7 shows the results from Dry Sieve Particle Size Analysis. Consolidation appears to be heterogeneous along the reservoirs. Sand failure is predicted to be between 50bar to 300bar depletion/drawdown (rough values) depending on layers consolidation. It is a high-pressure gas reservoir hence sand control is compulsory. Sand quality has been studied in each of the following reservoirs; Balta sands are quite coarse and Tarbert sands are a mix of a coarse facies and a fine one (d10 between 225 and 350µm). The fine facies were used for dimensioning the size of sand control screens with 250 µm aperture.

Tri-axial test predicted sand for around 200 bar depletion or draw down. The preceding prediction was made on plug situated at 3795m with a Specific Energy of 23 MPa. It can be seen in the following figure that some layers appears to be weaker. The weaker layers have Specific Energy of around 4 MPa. An empirical formula links Specific Energy to Unconfined Compressive Strength: UCS = 0.33 x SE1.37 (Formula valid for MPa and only for low values: SE < 50 MPa). With this formula, SE of 4 MPa gives UCS of 3 MPa (30 bar). A risk of sand production exists at 0 depletion when Draw Down exceeds 1,5 to 2 times the UCS, in this case: 45 to 60 bar (This ratio depend on the mechanical skin). When depletion will increase this draw down limit will decrease. Quite early sand production is hence expected in Brent reservoirs: Between 50 to 100 bar depletion added to drawdown.

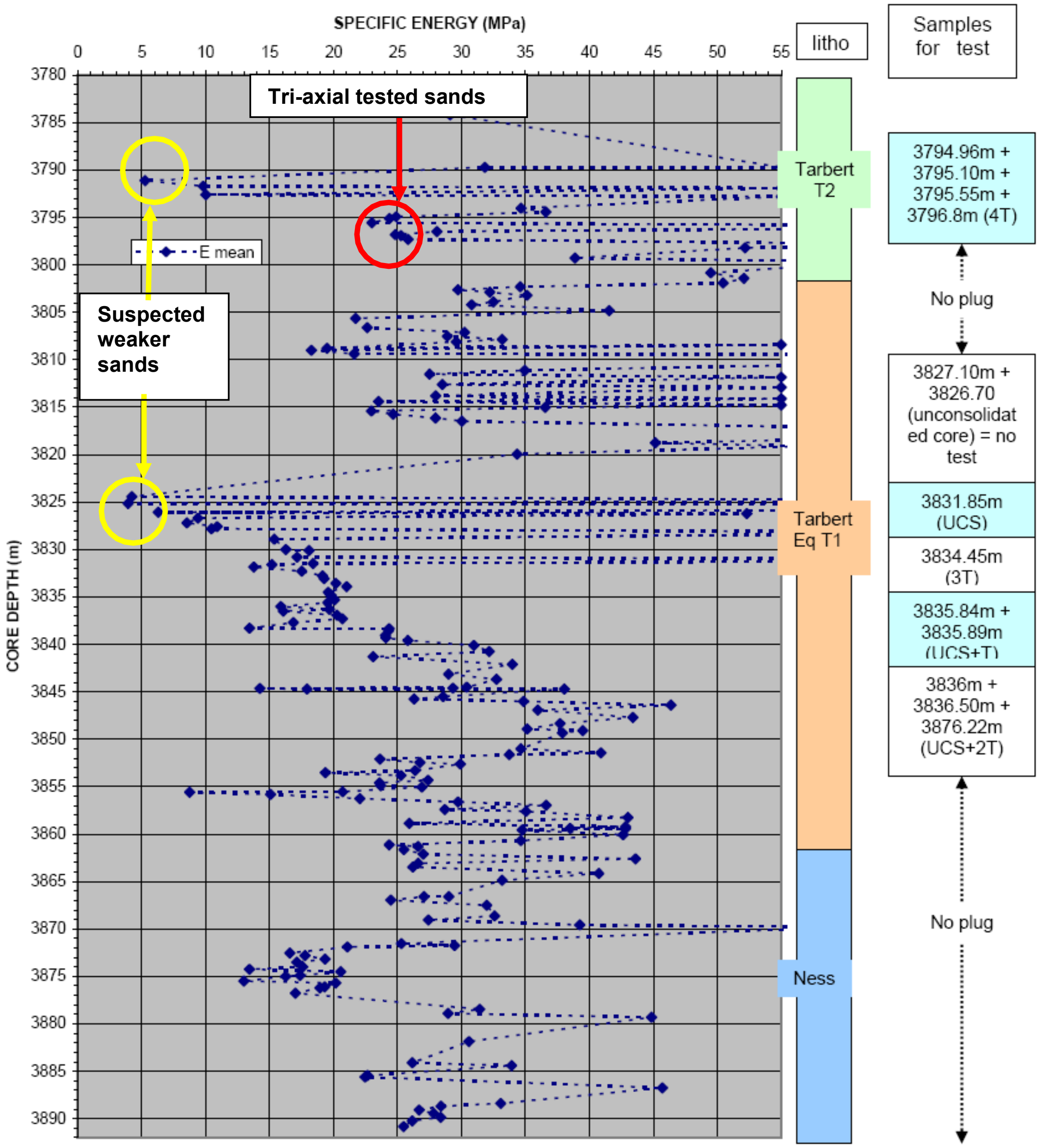

Figure 6 Scratch test on Cores from Well 30/4-2

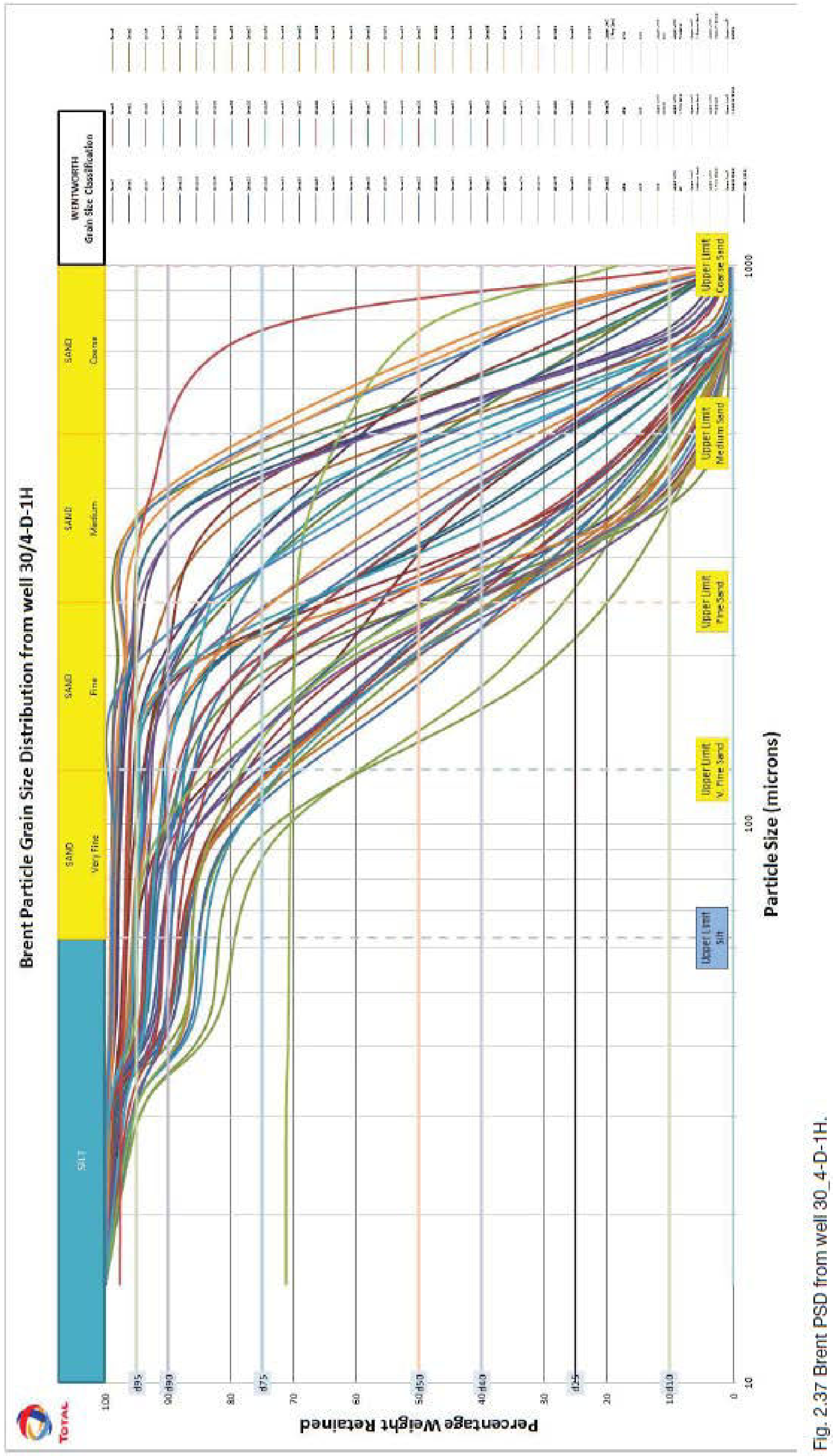

Figure 7 Dry Sieve Particle Size Analysis

Formation Sand characteristic coefficient ranges - Dry Sieve PSA ML field Brent formation sands

d50	**(microns)**	Max Min	940 93.4
Sorting Coefficient	**d10 / d95**	Max Min	29.03 3.58
Uniformity Coefficient	**d40 / d90**	Max Min	7.90 1.59
Square Root d25/d75	**Square Root (d25 / d75)**	Max Min	1.89 1.22

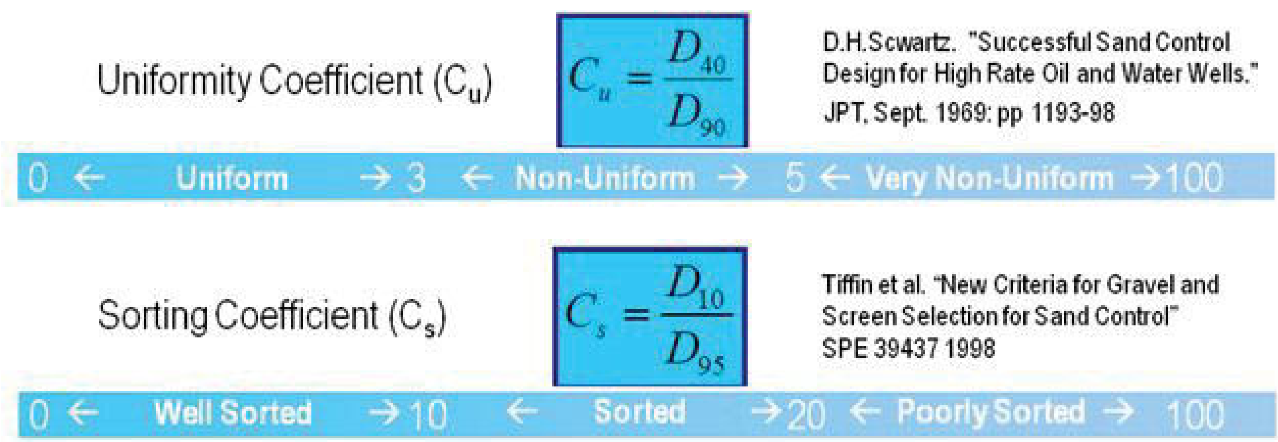

Figure 8 Formation Sand Characterisation - Summary

Scratch tests on cores

This section presents the information obtained on the scratch tests that were performed on the core samples originating from different formations in the reservoir section, which formed the basis of selection of sand control strategy and sand control screens.

Balta Formation

Balta is the uppermost formation characterized by several meters of very good reservoir, homogeneous sands below the Jurassic seal. Sand grains are Medium/Coarse/Very Coarse.

Particle size distribution

Particle Size Distribution of Balta Sands, values out of 4 tests, samples coming from well 30/7-8R are shown below

	d10 (µm)	d50 (µm)	d90 (µm)	Fines % < 44 µm	Cu = d40/d90
Median values	630	360	150	4	4
Worst values	550	275	60	8	6

PSD results are confirming geological description: Balta sands are rather coarse (Median d10 = 630) and well sorted (Median Cu = 4).

Tarbert 2 and 1 Formation

Tarbert 2 and 1 consist of alternating silty fine grained sandstones and silty shale deposited in bay-lagoon environments and medium to very coarse grained argillaceous to clean sandstones. Tarbert 2 permeability is 0.5 to 50 mD and Tarbert 1 is 10 to 2000mD. Top Tarbert 1 is characterized by a thick coal seam with an interbedded graded bed that is interpreted as a tsunami bed. The aforementioned claim is well evidenced in the wells at the Brent level in the ML Area as well as in many wells in the UK. This was identified potentially a dynamic barrier between the Tarbert 1 and the Tarbert 2 formations.

Particle size distribution

Particle Size Distribution of Tarbert 2 sands, values out of 4 tests, samples coming from well 30/4-2

	d10 (µm)	d50 (µm)	d90 (µm)	Fines % < 44 µm	Cu = d40/d90
Median values	757	340	49	10	11

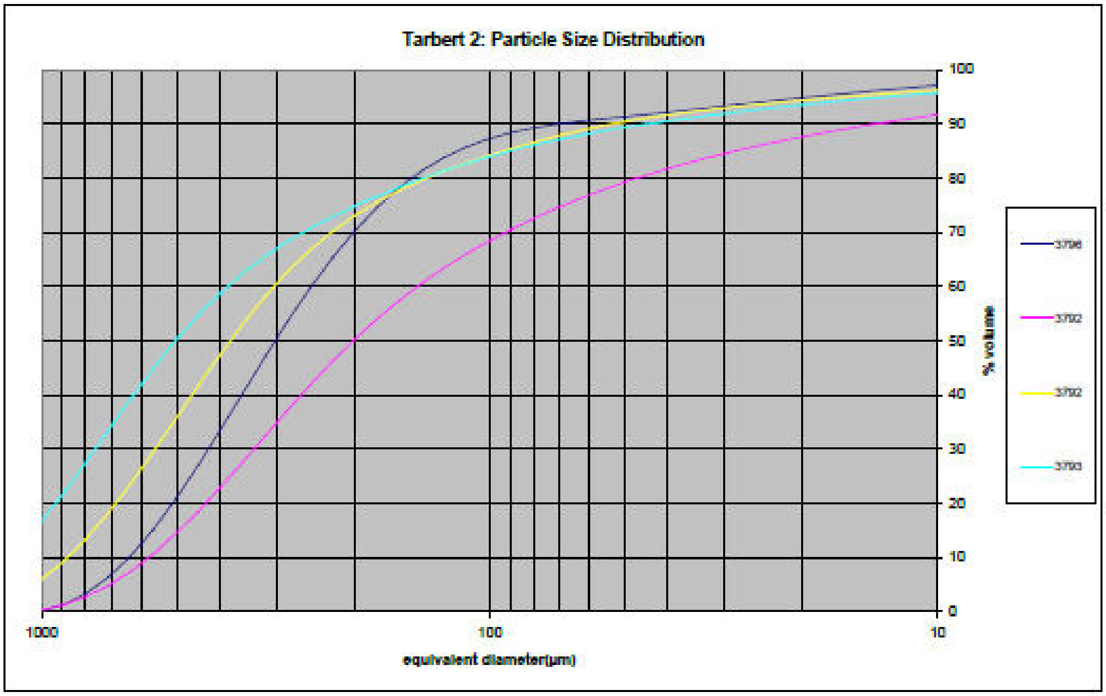

Figure 9 Tarbert 2 Particle Size Distribution, samples coming from well 30/4-2

PSD of Tarbert 1 sands, values out of 12 tests, samples coming from well 30/4-2

		d10 (µm)	d50 (µm)	d90 (µm)	Fines % < 44 µm	Cu = d40/d90
Median values	Fine facies	325	169	29	12	7
	Coarse facies	854	384	73	6	6

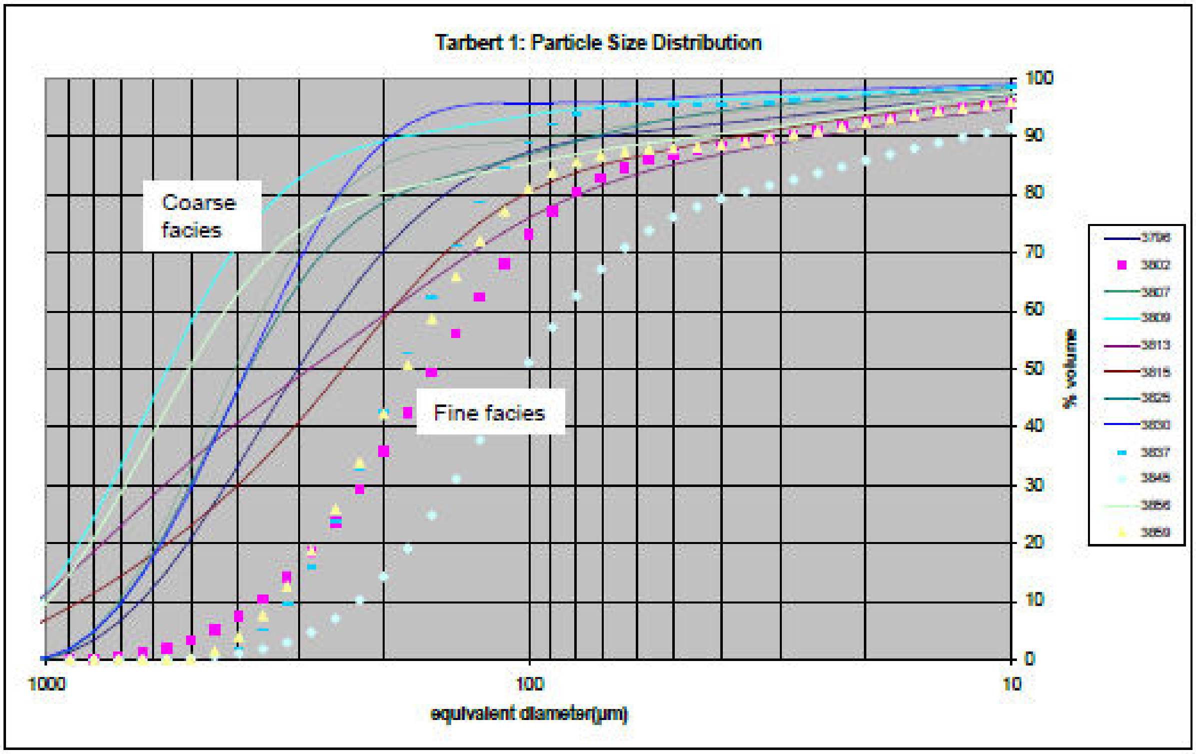

Figure 10 Tarbert 1 Particle Size Distribution, samples coming from well 30/4-2

As it can be seen through Tarbert 1 PSD, there are two different sand facies: One Coarse, which is equivalent to Balta and Tarbert 2 sands and a finer one. Both facies are spread over the reservoir height; therefore both facies will contribute to gas production. Sand control for wells crossing Tarbert 1 reservoir was hence included in the sand control design selection to hold the fine facies.

The table below gives the summary of PSD from reservoir formation

ML Gas Sand Definition

Reservoir			d10 (µm)	d50 (µm)	d90 (µm)	Fines % < 44 µm	Cu = d40/d90
Balta	Median values		630	360	150	4	4
	Worst values		550	275	60	8	6
Tarbert 2	Median values		757	340	49	10	11
Tarbert 1	Median values	Fine facies	325	169	29	12	7
		coarse	854	384	73	6	6

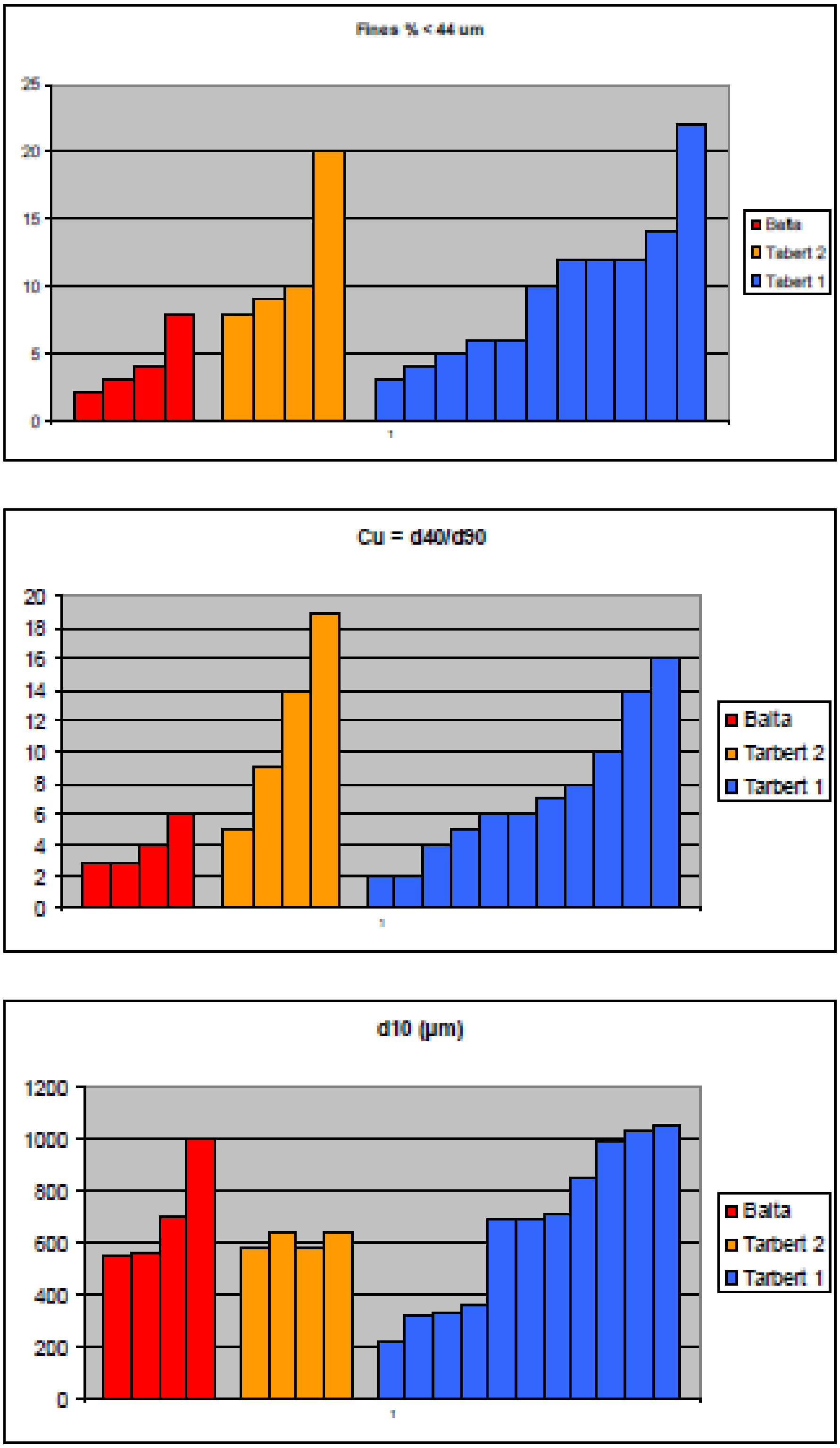

Figure 11 Sand Control Selection Summary

Balta sand is coarse and well sorted; from sand control point of view it is the less perplexing. Tarbert 2 sand is coarse, medium sorted. Tarbert 1 sand is divided in two facies. The coarser facies will not present excessive sand control challenges. The finer facies is medium sorted and has a higher fine content: this facies was used for dimensioning sand control for Tarbert reservoirs.

The study was performed for Brent Reservoir of the ML Gas Field based on core sample obtainable from the ML-East 1 Well. The following conclusion can be established based on the study:
- Sand production risk is evidently identified early in the field life (at low depletion levels)
- Selective perforation strategy is not advocated due to highly sand prone interval are scattered across the reservoir intervals, hence, there is a need for sand control completion
- Critical depletion varies from approximately 100 bars up to 750 bars

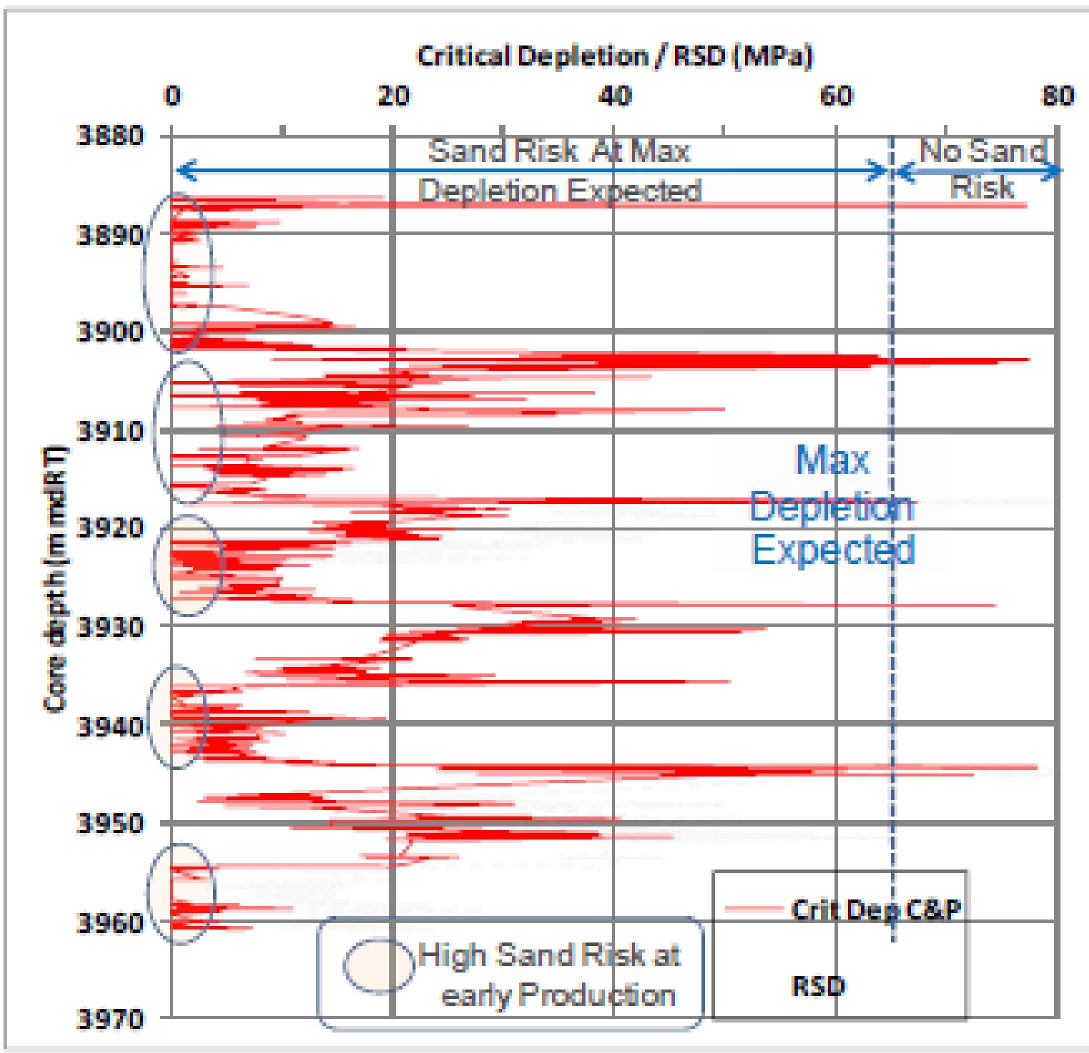

Figure 12Ccritical depletion profile from ML East 1 well

It can be concluded that during well life, sand failure will occur in nearly the whole interval. This conclusion confirms that sand control was required to complete sand face completion. Reservoir consolidation as studied by the geo-mechanics team suggested that there is a sanding risk in the Eastern panel, as some core materials were totally unconsolidated. It was nevertheless observed for the cores that could be scratch tested that “sanding risk with critical depletion prior to sand production was confirmed to be in the range of 190 – 210 bar”. It is noted that consolidation appears to be heterogeneous along the reservoirs hence sand failure is anticipated between 50bar to 300bar depending on a layer’s consolidation. For a gas well in such high pressures, depletion above the sand failure threshold is likely during the life of the well; therefore sand control is mandatory across the Sand face.

Screen Sizing
Sand control was sized using d10 values from Tarbert1 225-360µm and d50 of 100-180µm. Sand control using 250µm is adequate as larger particles will be able to create a bridge in order to start the natural sand pack formation process.

3.4 Well Plan and Completion [7, 8]

The Martin Linge jacket with a pre-drilling deck was installed on the Martin Linge field on location June 8th 2014. The Jack-up, Mærsk Intrepid, will be placed alongside the jacket’s east side and drill in cantilever mode through the slots on the pre-drilling deck.

The rig cantilever can reach all slots from its location and the cantilever has full load capacity on all slots. During the pre-drilling phase Maersk Intrepid is jacked up to an air gap of 28 m LAT and interfaced with the jacket via a bridge connected to Texas deck on the rig. The well slot layout for the Martin Linge platform consists of a wellhead deck with a 3 row x 7-column arrangement on a 2.50 m centre to centre spacing. The premeditated well slot layout on the platform is shown in Figure 13. The name of the well depends on the position of the slot. For e.g. the MLE-A well was drilled from slot no. 8, and will therefore the name 30/4-A-8.

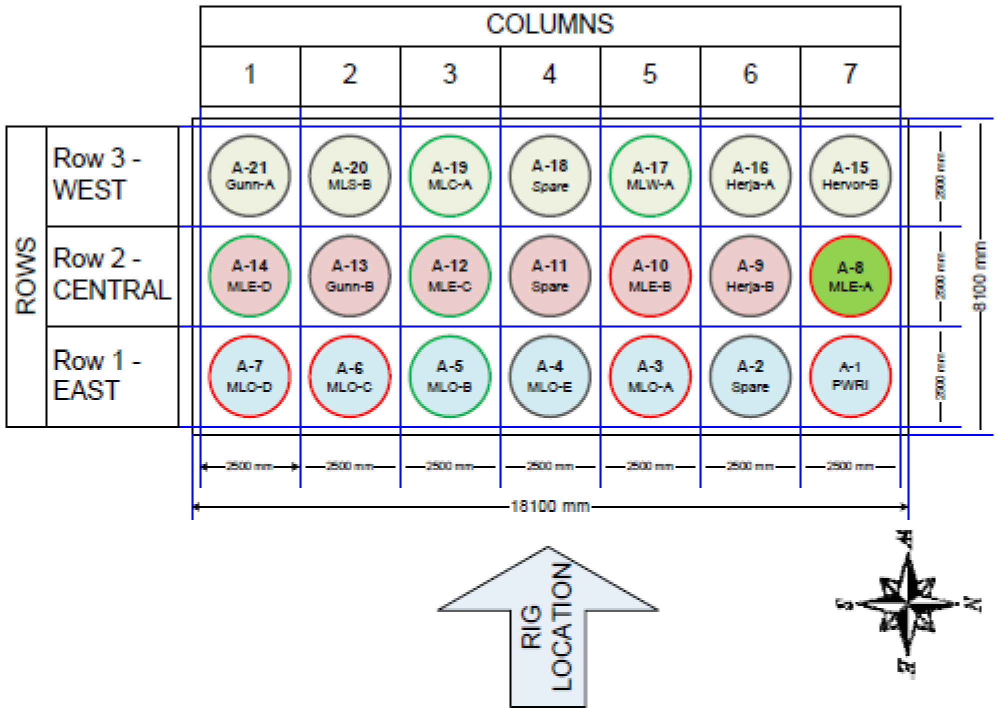

Figure 13 Slot layout on the platform Martin Linge

The rest of the thesis report will concentrate on the well A-8 (MLE-A), A-9 (Herja-B), A-10 (MLE-B) and A-12 (MLE-C) in which is used to evaluate their performance. Only basic well planning and completion information will be provided in order to get an outline of the wells that are subject of performance evaluation. The main focus is the planning and completion of reservoir section since performance evaluation of completion method is of interest, and not the entire well planning. Performance evaluation is done in the section 3.7 of this report.

Reservoir wellbore interface (RWI) completion method planned for all ML East wells was Weatherfords’ Expandable Sand Screens (ESS) according to the feasibility studies carried out for the sand control completions. ESS was found to be more trustworthy and unpretentious for installation than Stand-alone Screens (SAS) and open hole gravel pack completions. Later, the sand control strategy for A-12 well was however replaced from ESS to SAS. A discussion on the previous mention is to come later in the thesis

A-8 (MLE-A)

Well Plan

The A-8 (MLE-A) well was designed based on a maximum expected wellhead pressure of 624 bars, assuming a gas flow of 4 MSM3/day and a flowing wellhead temperature of 120 °C. Below is a schematic of the Brent well design (figure 14). The reservoir section was drilled in 37 days with 2.03-2.04 sg WARP mud. The reservoir interval drilled was 4520-4703 m MD with 30°

inclination throughout the interval. After drilling to TD, the well was displaced to 2,05 sg WARP screen run in fluid (sieved mud).

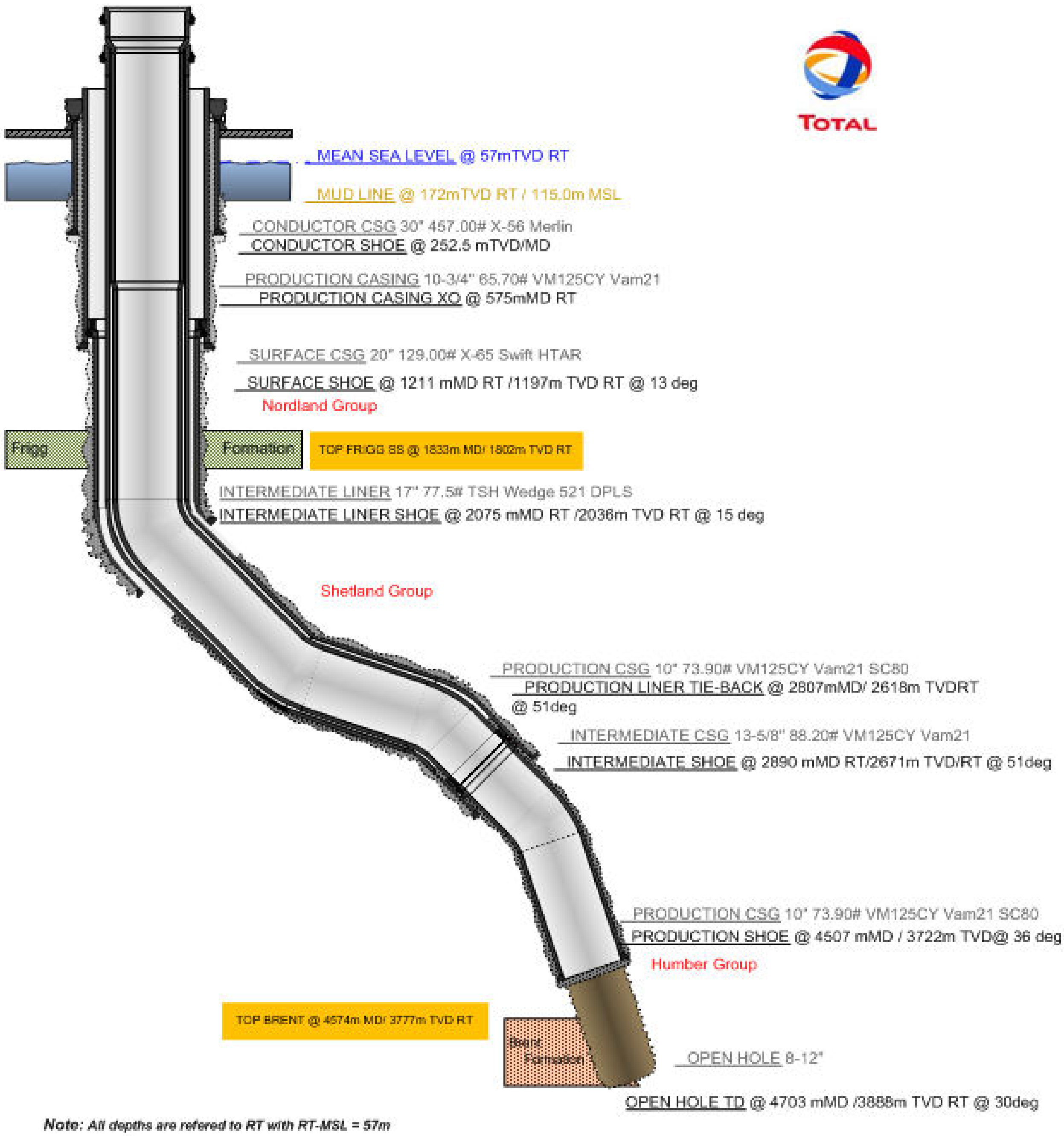

Figure 14 Well Plan A-8 (MLE-A)

Completion

Lower completion was run in 2.04 sg conditioned WARP mud and completion type was Weatherfords' expandable sand screens. In short the lower completion system comprised of 248m of 7'' Expandable Sand Screens (ESS) + Blank Pipe and EXR Liner Hanger Packer. ESS used is 250um mesh screen and is a compliant expanded system, hence the screen touches the bore hole wall. The mud was conditioned through 230 micron Mesh Production Screen Tester to ensure no solid content were present in the mud when running the screens so that mud particles do not block the screen openings. It look 3.5 days to install lower completion.

After sucessful installation and expansion of screen, intermediate completions assembly was installed including glass plug, which took 10 days to complete. After the setting of glass the plug, the well above the glass plug was first displaced to 1.65 sg seawater and subsequently the well was displaced from seawater to 2.04 sg Cesium-Formate brine. The remaining upper completion took 10 additional days to complete.

A-9 (Herja-B)

The Herja well was initially an exploration well named 30/4-3 going to the northern part of the ML structure. The name was however converted to 30/4 A-9 when substantial HC volumes were proven in the BRENT reservoir.

Well Plan

The A-9 (Herja) well was designed based on a maximum plausible wellhead shut in pressure of 640 bar and a gas flow of 4 M SM^3/day and a flowing wellhead temperature of 120 °C. Below is a schematic of the well design (figure 15). The reservoir section was drilled in 19.2 days with 2.05-2.07 sg WARP mud. The reservoir interval drilled was 4150-4605 m MD with 30° inclination throughout the interval. After drilling to TD, the well was displaced to 2,05 sg WARP SRiF.

Completion

Lower completion was run in 2.06 sg conditioned WARP mud and completion type was Weatherfords' expandable sand screens. In short the lower completion system comprised of 427m of 7'' Expandable Sand Screens (ESS) + Blank Pipe and EXR Liner Hanger Packer. Total length covered by expandable ESS is 252m. ESS used is 230um mesh screen and is a compliant expanded system, hence the screen touches the borehole wall. The mud was conditioned through 230 micron Mesh Production Screen Tester to corroborate that no solids content were present in the mud when running the screens so that mud particles do not block the screen openings. It took 3.3 days to install the lower completion.

After successful installation and expansion of screen, intermediate completions assembly was installed including glass plug which took 7.6 days to complete. Subsequent of the setting of the glass plug, the well above the glass plug was first displaced to 1.65 sg seawater and afterwards the well was displaced from seawater to 2.12 sg Cesium-Formate brine. The remaining upper completion took 10.5 more days to complete.

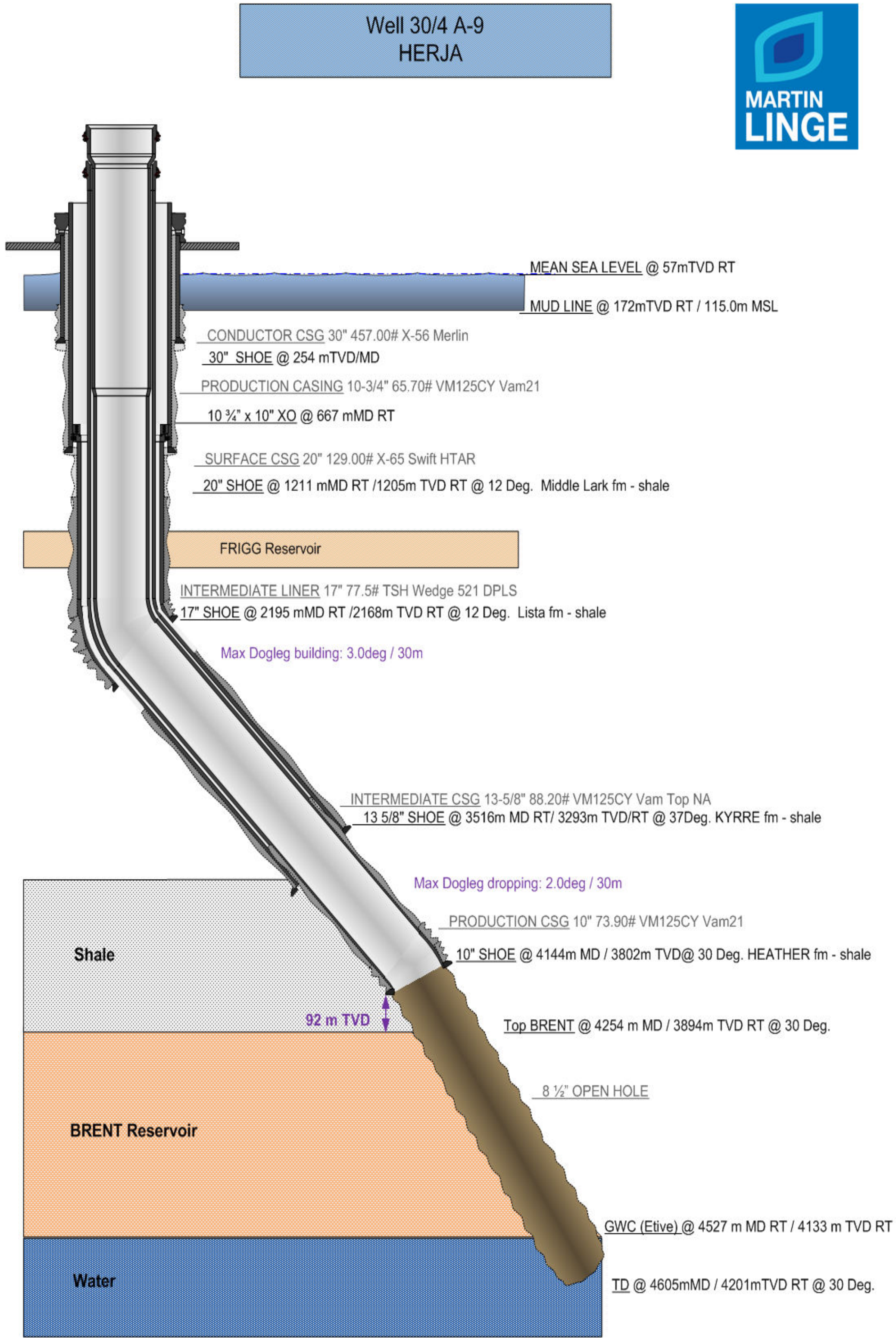

Figure 15 Well Plan A-9 (Herja-B)

A-10 (MLE-B)

Well Plan

The A-10 (MLE-B) well was designed based on a maximum expected wellhead pressure of 624 bars, assuming a gas flow of 4 MSM3/day and a flowing wellhead temperature of 120 °C. Below is a schematic of the Brent well design (figure 16). The reservoir section was drilled in 32 days with 2.00-2.04 sg NABM WARP mud. The reservoir interval drilled was 4514-4690 m MD with 33° inclination throughout the interval. After drilling to TD, the well was displaced to 2,04 sg WARP screen run in fluid (sieved mud).

Completion

Lower completion was run in 2.04 sg conditioned WARP mud and completion type was Weatherfords' expandable sand screens. In short the lower completion system comprised of 170m of 7'' Expandable Sand Screens (ESS) + Blank Pipe and EXR Liner Hanger Packer. ESS used is 230µm mesh screen and is a compliant expanded system, hence the screen touches the bore hole wall. The mud was conditioned through 230 micron Mesh Production Screen Tester to make sure no solids content were present in the mud when running the screens so that mud particles do not block the screen openings. It look 3.5 days to install lower completion.

After successful installation and expansion of screen, intermediate completions assembly was installed including glass plug, which took 10 days to complete. After setting of glass plug, the well above the glass plug was first displaced to 1.65 sg seawater and then the well was displaced from seawater to 2.04 sg Cesium-Formate brine. The remaining upper completion took 10 more days to complete.

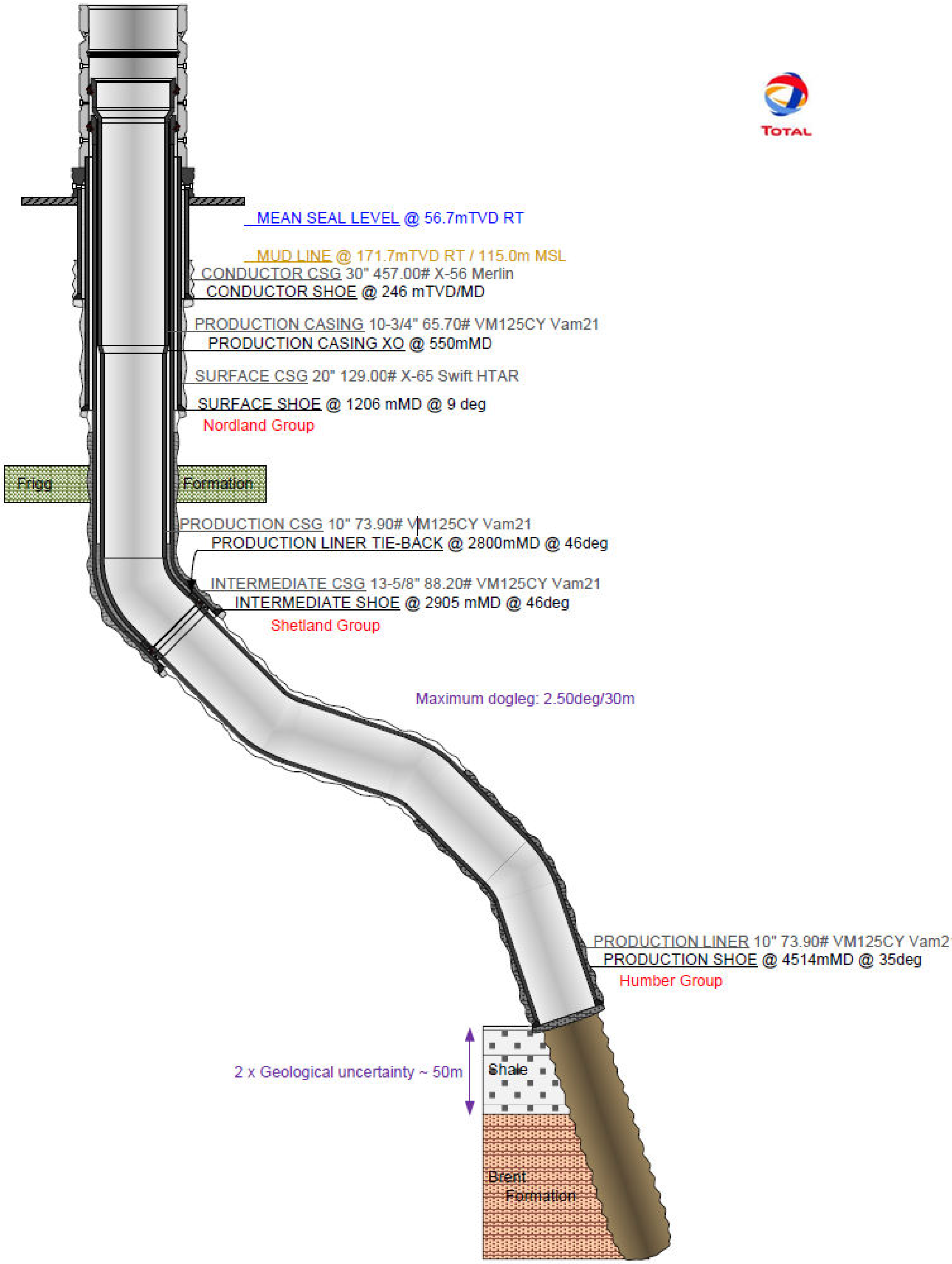

Figure 16 Well Plan A-10 (MLE-B)

A-12 (MLE-D)

Well Plan

The A-12 (MLE-D) well is currently being drilled during the preparation of this report and after the completion of the well, it will provide a decent comparison to evaluate the ESS sand control completion used in previous gas wells since the completion strategy for A-12 has been altered. The A-12 well is designed based on a maximum expected wellhead pressure of 623 bars, assuming a gas flow of 4 MSM3/day and a flowing wellhead temperature of 120 °C. Below is a schematic of the Brent well design (figure 17). The A-12 well design includes two major differences in comparison to the other Brent wells, it is drilled with CsF mud and the lower completion currently consists of standalone screens (SAS). For A-12 well the choice of RDiF was Cs/K (Cesium/Potassium Formate) WBM based on the previous clean-up difficulties and respective low PI's obtained on A-8, A-9, A-10 wells and updated Cs/K Formate formulation testing and formation damage test results. The reservoir section was drilled in 9 days with 2.02-2.05 sg Cs/K Formate WBM with adequate fluid loss control via polymers and bridging particles (80-100 kg/m^3 $CaCo_3$). The reservoir interval drilled was 4857-5002 m MD with 30° inclination throughout the interval. After drilling to TD, the well was displaced to 2,05 sg Cs/K Formate SRiF (sieved mud).

Completion

Lower completion was run in 2.05 sg conditioned Cs/K Formate WBM mud and completion type was Stand Alone Sand Screens (wirewrap type screens) with 250µm filter across RWI . In short the lower completion system comprised of 125m of 6 5/8'' Stand Alone Sand Screens (SAS) + Blank Pipe and EXR Liner Hanger Packer. The mud was conditioned through 230 micron Mesh Production Screen Tester to make sure no solids content were present in the mud when running the screens so that mud particles do not block the screen openings. It took 4 days to install lower completion.

The lower completion string was run with a glass plug just below the screen hanger packer. After verifying the integrity of the glass plug, the well above the glass plug was displaced to 2.10 sg Cesium-Formate brine. The remaining upper completion took 15 more days to complete. The remaining upper completion took 15 more days to complete.

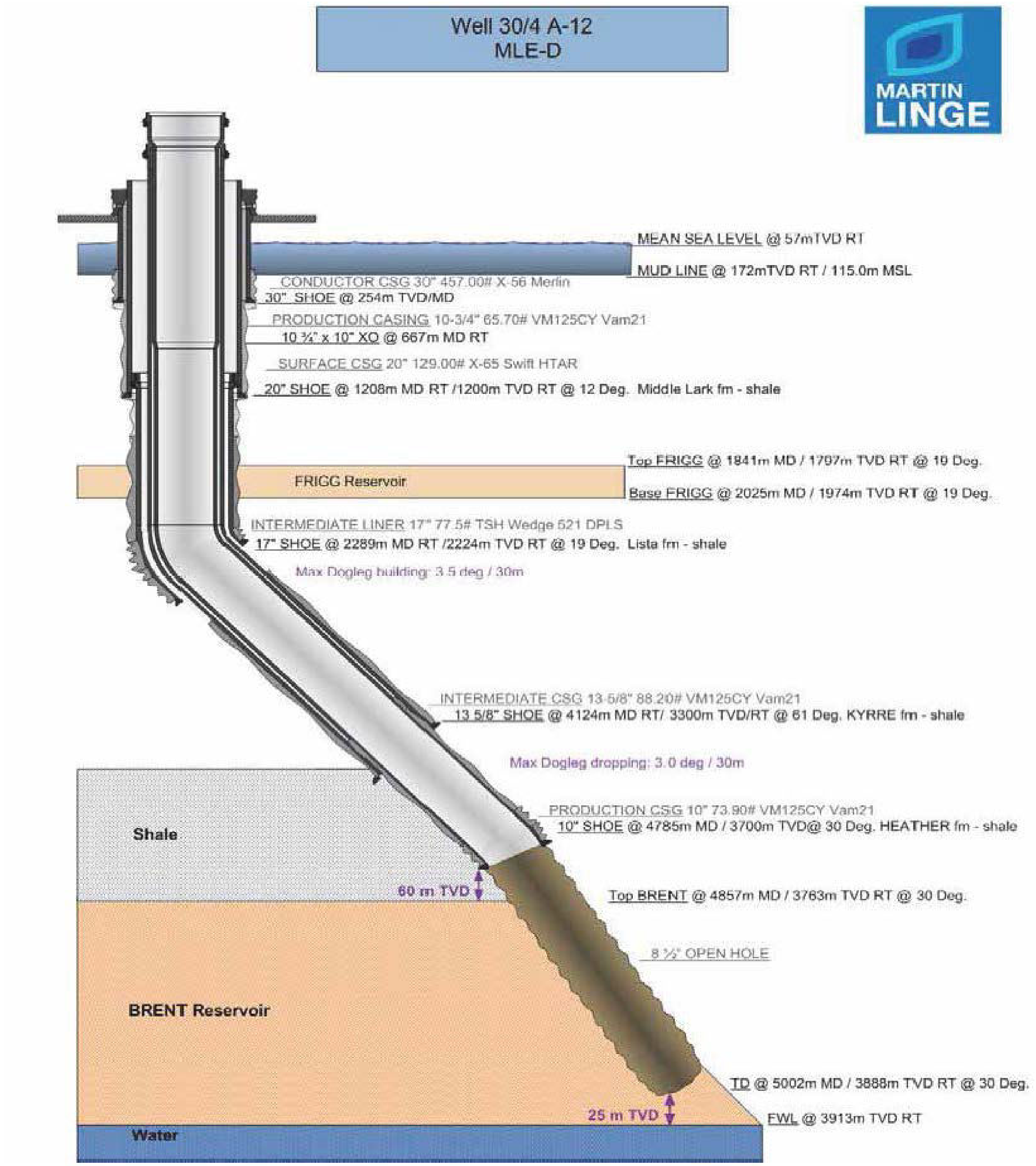

Figure 17 Well Plan A-12 (MLE-D)

3.5 Production Data from ESS Completed ML Gas Wells

This section presents significant real time data that will be applied for the analysis and discussion in later section.

A-8 (MLE-A) Production Clean-Up

After successful completion of well it was temporarily shut-in for 26 days until it was opened for production clean-up. An 82 hours long production clean-up test was performed from May 31st to June 6th, 2016. The well was successfully cleaned up with a maximum gas production of ~1.5 MSm^3/day with a drawdown of 14.5 bar, yielding a Productivity index of ~100 KSm3/d/bar. Fluid samples were gathered from the surface separator during the main flow periods. After successful clean-up, a temporary abandonment cap was installed on the unihead and the well will temporarily shut-in until it will be opened for production in 2018 for combined production with other gas wells.

A-9 (Herja-B) Production Clean-Up

After successful completion of well it was opened for production clean-up immediately. It was prepared to clean-up right after installing the completion. Production clean-up test was performed from September 30th to October 4th, 2016. The well was cleaned up with a maximum gas production of ~1.3 MSm^3/day with a drawdown of 30 bar, yielding a Productivity index in the range of ~80-100 KSm3/d/bar. Fluid samples were gathered from the surface separator during the main flow periods. After successful clean-up, a temporary abandonment cap was installed on the unihead and the well will temporarily shut-in until it will be opened for production in 2018 for combined production with other gas wells.

A-10 (MLE-B) Production Clean-Up

After successful completion of well it was temporarily shut-in for 131 days until it was opened for production clean-up. A solitary possibility was to flow well for first clean-up flow, but that was with lack of success as well. The reason being that lot of debris/mud solids were encountered after initial clean-up above the glass plug, assumed as mix of formation sand and sagging from solids in the SRiF. Observed restrictions to flow downhole due to significant pressure drop and maximum pressure drop across ESS restricted further flowing of the well. For treatment 33m^3 of MEG/water solution was left in the well. But, from first clean up maximum gas production of ~600 kSm^3/day with a drawdown of 70 bar, yielding a Productivity index of ~90 KSm3/d/bar was recorded. As can be seen very low PI was obtained, so it will be irrelevant to take the PI of this well into analysis. So, analytical PI calculations will be presented that should have been expected with comparing them to other 2 wells by assuming reduced PI like 2 other wells.

3.6 Production data from SAS gas well A-12

After successful completion of well it was opened for production clean-up immediately. It was prepared to clean-up right after installing the completion. The well was just opened on 10th July 2017, during the preparation of this report and only the first clean-up has been completed. To get a good idea and include this well in the analysis, the observed value from first clean-up was asked to rig personnel supervising the clean-up operation. According to his information, the first clean-up was with a maximum gas production of ~1.2 MSm^3/day with a drawdown of 42 bar, yielding a Productivity index in the range of ~200 KSm3/d/bar. Further clean-up will continue for this well which will give exact PI value for the well and would be interesting to see that SAS gives better clean-up. But, since this report needs to be submitted now, we will assume the value from first cleanup as the final value. After successful clean-up, a temporary abandonment cap will be installed on the unihead and the well will temporarily shut-in until it will be opened for production in 2018 for combined production with other gas wells.

3.7 Suspension Time

Suspension time/static time between installation of ESS and clean-up flow is an essential data as SRiF was left static in the hole around reservoir section for particular time after drilling. As the time goes by there might be fluid invasion in the formation and this might alter the normal properties of filter cake due to high temperature and fluid properties.

A-8 (MLE-A)
50 days - Well was temporarily shut in with SRiF inside the well for 50 days between installing ESS (expansion) and flowing well.

A-9 (Herja-B)
25 days – Static time between installing ESS (expansion) and flowing well for 25 days. Clean up performed directly after installing upper completion.

A-10 (MLE-B)
164 days – The well was temporarily shut in with SRiF inside the well for 164 days between installing ESS and flowing well. Followed by that, only one unsuccessful clean-up flow was achieved, after which it was shut in until the remedial operations will be performed to remove the debris above the glass plug.

A-12 (MLE-D)
15 days - Static time between installing ESS (expansion) and flowing well for 15 days. Clean up performed directly after installing upper completion.

3.8 Fluid Tests

This section presents various tests performed with fluids on ESS samples. Solely conclusions from this tests are presented. Laboratory testing was conducted to evaluate the mud systems for their technical feasibility in terms of Drilling and Completion operations. Wells will require drill-in fluid densities of 2.00-2.04 sg, while bottom hole static temperature is +/- 140 °C. There is no track history for these completion methods, with any operator , for either NABM or WBM at such high densities or temperatures.

Testing was carried out at two facilities:

1. MISWACO – Martin Linge drilling and completion fluids supplier (Stavanger and Bergen test labs)
2. Weatherford – Martin Linge ESS system supplier (Aberdeen test lab).

The following testing has been performed to date and is outlined in Table 2

Testing	Object	Comments
Fluid formulation:	To demonstrate the stability of the fluid systems under expected wellbore conditions.	
Formation Damage (FDT):	To assess the formation damage of the mud systems and subsequent impact for well productivity.	
PST Screen plugging (PST):	To demonstrate the ESS screens will not plug with the selected RDiF / SRiF.	For screen installation.
Flow Back Testing (FBT):	To demonstrate the filter cake will flow back through the ESS screen.	For flow back and cleanup of the wells
Compatibility Testing:	To assess the compatibility of WARP and Cs/K Formate RDiF systems.	For completion operations where displacement to Cs/K Formate SRiF is performed after drilling the reservoir section with WARP NABM RDiF.

Table 2 Fluid Testing Summary

As summary of the test results can be seen in Table 3

Test	Results	Comments
Fluid formulation @ MI	WARP - OK Cs/K - OK	Optimisation as required by test results.
PST @ MI	WARP - OK Cs/K – OK	No plugging of screen observed for any test. Volume flowed though not sufficient to mimic down hole conditions.
PST @ WFD	WARP - OK Cs/K – OK	Observed plugging for unconditioned WARP mud, No plugging after conditioning (via 200/230 Mesh screens)
FBT @ MI	WARP - OK Cs/K – not done	Low pressure observed for flow-back test – no plugging ***Note:*** ESS coupon not pushed into filter cake so results considered indicative only for ESS.
FBT @ WFD	WARP Short term Flow-back – OK Long term Flow-back (Aging) – Not good Cs/K – OK	Low pressure observed during short term flow-back – indicates no plugging. Long term flow-back results disregarded as an artifact of testing apparatus. Cs/K Formate less prone to plug screens.
Compatibility @ MI	Cs/K/Formation water+ Base oil+ emulsifier - OK Cs/K Formate against WARP filter cake - negative	No compatibility issues seen for various blends Had breakthrough of Cs/K Formate through WARP filter cake in short time for two parallel tests. Cs/K destroys WARP filter cake.
FDT @ MI	WARP - OK Cs/K Formate – Poor.	WARP shows significantly lower potential for formation damage

Table 3 Fluid Testing Results Summary

Conditioning test

Based on results, if the fluids provided are representative of that to be used in the field then for the WARP muds conditioning at 75 microns potentially prevents plugging problems. However, the tests were performed on a laboratory sample and it is likely that solid loadings in the field will be higher, therefore it is advisable to have 53 micron screens available.

The Caesium formate fluid showed significantly less plugging than the WARP muds, and exposure to high shear before testing prevented plugging from occurring. In the field the mud will of course require conditioning to remove drilled solids prior to deploying the screens. Fluid suitability should always be confirmed with rig site tests before running the screens to ensure no plugging will occur.

Drilling fluid filter cake flow back

The drill-in fluid was a laboratory sample supplied by MI labeled OB warp formulation 2.04 SG. The results indicate that the mud solids were transported through the ESS weave without difficulty, but the high solids loading and ‘sticky’ nature of the mudcake meant that they weren’t transported out of the test cell. Once a flowpath has been instigated through the mud to the exit tube from the core holder there is little impetus for displacing the solids further.

Formate Drilling fluid filter cake flow back

Based on the results of the aforementioned tests the presence of the 230 ESS doesn't influence the clean-up obtained with this mud, and the reduction in permeability observed is possibly due to plugging of the pore matrix. Shutting in the mud for a number of days after screen insertion before flowing oil does not greatly affect the result although the return permeability is noticeably reduced. Further clean-up may be achieved in the field compared to the laboratory tests due to the much larger oil volumes that will flow with time. It should also be noted that permeability changes observed in these tests cannot be related to the field situation in terms of formation damage, since field materials were not used (apart from the mud), and fluid volumes and flow rates are different from the field situation.

Reservoir Drilling / Sandface Completion / Fluid

Specially designed WARP mud was used in the completion of the initial wells, where productivity constraints were observed. In a review, currently underway to confirm the specific causes of the challenges observed, it has been noted that an unusually thick filter cake (which is sticky instead of friable) may be a key factor in the negative well results.

Consequently, an alternate fluid, Caesium Formate (CsCOOH) has been evaluated to ascertain suitability as a sand-face completion fluid. Other formulations of Caesium formate have been evaluated in previous tests, with results generally unsatisfactory due to the presence of damage that may be associated with polymer effects on the oil wet surfaces of reservoir matrix.

The objectives of the latest evaluation trough laboratory tests and analysis were;

- Estimate matrix damage (hence, the retained permeability) caused by RDF invasion of the matrix
- Confirm that screen is not plugged during well flowback by measuring pressure drop / retained permeability of a flooded matrix, cake and screen setup
- Compare results of Cs/K formate and WARP mud

Summary of results obtained from the tests are as presented in Table 4: RDF / Completion Fluid test Results

Test #	RDF / Comp. Fluid	Screen	T (°C)	Prod Fluid A	Kr 1 (%)	Initial Damage B (%)	Max dP screen (mbar)	LOP (mbar)	Kr2 post cake removal (%)	Damage post cake removal C (%)	Damage due to cake D (%)
1	Cs/K Formate + LCM	No screen	140	NaCl Brine	42	58	-	12	71	29	29
2	Cs/K Formate + LCM	No screen	140	Marcol-52	43	57	-	8	83	17	40
3	Cs/K Formate + LCM	Mesh 250 µm	140	Marcol-52	73	27	12	14	92	17	10
4	Cs/K Formate + LCM	WWS Slot 10	140	Marcol-52	58	42	6	19	72	28	14
5	WARP + LCM	No screen	140	Marcol-52	69	31	-	6	71	29	2
6	WARP + LCM	Mesh 250 µm	140	Marcol-52	77	23	6	20	79	21	2
7	WARP + LCM	WWS Slot 10	140	Marcol-52	87	13	6	5	88	12	1

Table 4 RDF / Completion Fluid test Results

The results from the table can be interpreted as follows

Initial Damage - B (%): It is assessed as the percentage of permeability lost after the reservoir wellbore interface model has been flooded with expected connate fluid, RDF flowed through from wellbore into the matrix to build a mud cake and then production fluid from the matrix is flowed back into the wellbore. This damage is due to external (cake) and internal (matrix) restriction to flow.
It is observed that initial damage is significantly (~20%) higher when Cs/K Formate is used as RDF/Completion fluid in comparison with WARP OBM. There is no obvious explanation for this observation. An atomic level evaluation may lead to a better understanding.

Damage post cake removal C (%) and damage due to cake D (%): Further to depressurization of the set up and mechanical removal of the cake formed on the matrix, a re-assessment of the retained permeability is made in order to confirm what portion of the damage is due to restrictions in the matrix.
In this scenario, it is observed that damage left in the matrix is slightly lower in Cs/K brine RDF system compared to the WARP system (except when WWS is used). It is also deduced that the damage due to the cake is significantly higher in CS/K system than in the WARP system.

The following initial deductions can be made based on the fore-mentioned observations;
- Filter cake is main damage mechanism of Cs/K RDF system (accounting for 30-60% of damage)
- Minimum damage (and maximum retained permeability) is obtained when the filter cake is removed from a CS/K brine Completion system
- Matrix restriction is the principal damage mechanism of the WARP/OBM system (>90%), therefore target of a WARP damage treatment should be aligned accordingly

Observations on the cake

Other observations made on the cake after the flowback sequence include;

WARP OBM filter-cake remained largely intact, after the flowback operation was completed. However a hole was observed on the edge of the cake and it is evident that fluid flows through the setup were routed through this opening in the filter cake. This is confirmed by the fact that mechanical removal of the filter cake led to minimal (<10%) change D, when final damage C is compared with initial damage B. Recall that a hole in the cake has been common feature of previous tests on WARP mud (**Figure 18: WARP mud cake tests showing holes**)

Figure 18 WARP OBM filter cake after flowback

Cs/K formate filter cake appeared to be sintered and fully dispersed after the flowback. However, the reason(s) for the significant change in retained permeability is not evident, in view of the relatively thin (2mm) layer of cake formed on the matrix (figure 19)

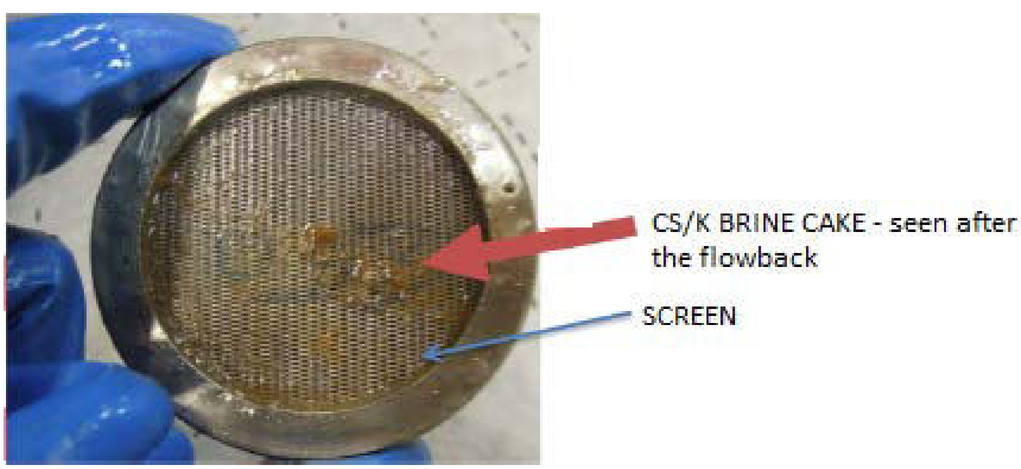

Figure 19 Mesh Screen and Cs/K brine cake after flowback

In terms of Completion Fluids, the following definite deductions can be made

- Minimum damage (and maximum retained permeability) is obtained when the filter cake is removed from a CS/K brine completed wellbore
- Damage in the matrix (or near wellbore) is the principal damage mechanism of the WARP/OBM system (>90%), therefore target of a WARP damage treatment should be aligned accordingly
- For WARP OBM, retained permeability observed in the screen – cake - matrix setup represents flow through a hole in the mud. This type of opening is the cake though which all flow is directed is a basis for hot-spotting and consequent loss of sand control means.

3.9 Calculations and Simulations

This section presents the input reservoir parameters used for calculations and simulating the expected and obtained productivity of the wells. The table 5 & 6 below gives the reservoir data obtained from exploration wells drilled before planning of the field.

The objective of this chapter is to assess a conservative order of magnitude of Brent East wells productivity in order to simulate the clean-up operation. Later in the thesis these results will be compared with real time results from clean-up operation.

The mechanical skin value represents the damage of the wellbore interface by the drilling operation. The higher the skin, the more cautious the clean up (due to the risk of creating a “hot-spot”). Nevertheless, this skin value is unknown until the well is cleaned-up and a pressure build-up is interpreted. So, in this calculation the skin value is manipulated until expected PI is obtained. According to the results, the skin has a mean value of around 50 on ESS wells due to the expected significant damage caused by the heavy mud-cake in Brent high-pressure wells.

The effective productivity index (PI) will be known at the end of the clean-up operation. Here an attempt to deduce a rough PI value from the reference reservoir data provided by the reservoir department is done before drilling of the wells for assessment of the reservoir deliverability.
However, the Eclipse PI may be optimistic as noticed in previous development projects from past experience. One of the conceivable reasons for this optimistic productivity is the fact that Eclipse model productivity refers to the static pressure confined in the nearest 9 cells around the wellbore instead of the average static pressure in the drainage area. Therefore, on the basis of TOTAL’s past experiences a 50% safety factor on Eclipse PI values is applied. This assumption appears to be both realistic and conservative when compared to the PI’s calculated according to reservoir characteristics for the Clean-up study.

Brent East wells	MLE-B		MLE-A	
Reservoir fluid	Cond-gas		Cond-gas	
PVT data				
Pres (t0) (bar.a)	733		705	
Tres (°C)	139		139	
Dew Pressure: P.sat(Tres) (bar.a)	737		737	
Average pressure in drawdown zone: Pav	726		700	
Gas viscosity at (Pav, Tres): μg (cP)	0.039		0.038	
Gas compressibility at (Pav, Tres): Zg (-)	1.459		1.429	
BH Gas density in STD cond: ρg (kg/Sm3)	0.943		0.943	
Reservoir data				
Facies	Transgressive	Non-transgressive	Transgressive	Non-transgressive
Reservoir Net thickness (NTG = 100%) (m)	16.6	38.1	20.2	69.9
Wellbore deviation from vertical (degree)	34	same	32.7	same
Net producing length: Lp (m)	20	46.3	24	83.1
Horizontal permeability: Kh (mD)	2613	60	2613	60
Vertical permeability: Kv (mD)	871	0.2	871	0.2
Wellbore radius: rw (m)	0.108	same	0.108	same
Length of drainage area (along well axis) (m)	85	same	132	same
Width of drainage area (perpendicular) (m)	1200	same	1000	same
Shape factor of drainage area: Ca	1	same	2	same
Turbulence factor: D (*) (d/Sm3)	3.5 e-6	5.9 e-6	3.0 e-6	3.3 e-6

(*) the turbulence factor is calculated here with KATZ model

Table 5 Brent East Reservoir Data well MLE-B and MLE-A

Brent wells	MLE-D		MLE-Herja B	
Reservoir fluid	Cond-gas		gas	
PVT data				
Pres (t0) (bar.a)	703		733	
Tres (°C)	139		139	
Dew Pressure: P.sat(Tres) (bar.a)	737		737	
Average pressure in drawdown zone: Pav	700		244	
Gas viscosity at (Pav, Tres): μg (cP)	0.038		0.022	
Gas compressibility at (Pav, Tres): Zg (-)	1.428		0.979	
BH Gas density in STD cond: ρg (kg/Sm3	0.943		0.943	
Reservoir data				
Facies	transgressive	Non-transgressive	transgressive	Non-transgressive
Reservoir Net thickness (NTG = 100%) (m)	25.9	60.1	19.9	120.2
Wellbore deviation from vertical (degree)	36	same	33.8	same
Net producing length: Lp (m)	32	74.3	24	145
Horizontal permeability: Kh (mD)	2613	60	2613	60
Vertical permeability: Kv (mD)	871	0.2	871	0.2
Wellbore radius: rw (m)	0.108	same	0.108	same
Length of drainage area (along well axis) (m)	135	same	238	same
Width of drainage area (perpendicular) (m)	580	same	1200	same
Shape factor of drainage area: Ca	15	same	10	same
Turbulence factor: D (**) (d/Sm3)	2.2 e-6	3.8 e-6	4.7 e-6	3.0 e-6

(*) the turbulence factor is calculated here with KATZ model

Table 6 Brent East Reservoir Data well MLE-D and MLE- Herja B

The table 7 below provides the initial production targets that were expected from the wells

		Initial production target				Formation water
Brent zone	well	Qgas MM.Sm3/d	Qcond m3/d	Qwater m3/d	CGR m3/MM.Sm3	WGR m3/MM.Sm3
East	**A-9**	**4.000**	843	149	211	37
East	**A-8**	**2.249**	474	3	211	1
East	**A-12**	**2.968**	625	1	211	0
East	**A-10**	**2.850**	280	6	98	2

Table 7 initial production targets

Table 8 shows PI values assuming 50% of Eclipse PI as mentioned above that TOTAL's past experiences a 50% safety factor on Eclipse PI values is applied.

		Eclipse model			50% of Eclipse PI		
Brent zone	well	Pres bara	drawdown bar	Eclipse PI-gas k.Sm3/d/bar	PI-gas k.Sm3/d/bar	Drawdown bar	Skin (Sm)
East	**A-9**	733	8	500	250	16	54
East	**A-8**	705	4	562	281	8	41
East	**A-12**	703	8	450	225	16	51
East	**A-10**	248	3	950	475	6	50

Table 8 50% of Eclipse PI

Figures 20, 21, 22 & 23show expected inflow performance relationships (IPR) expected from the wells. Graphs shows both transgressive (high permeable zones) and non- transgressive facies (low permeable zones), but we are most interested in transgressive facies since that contributes to most of the gas production.

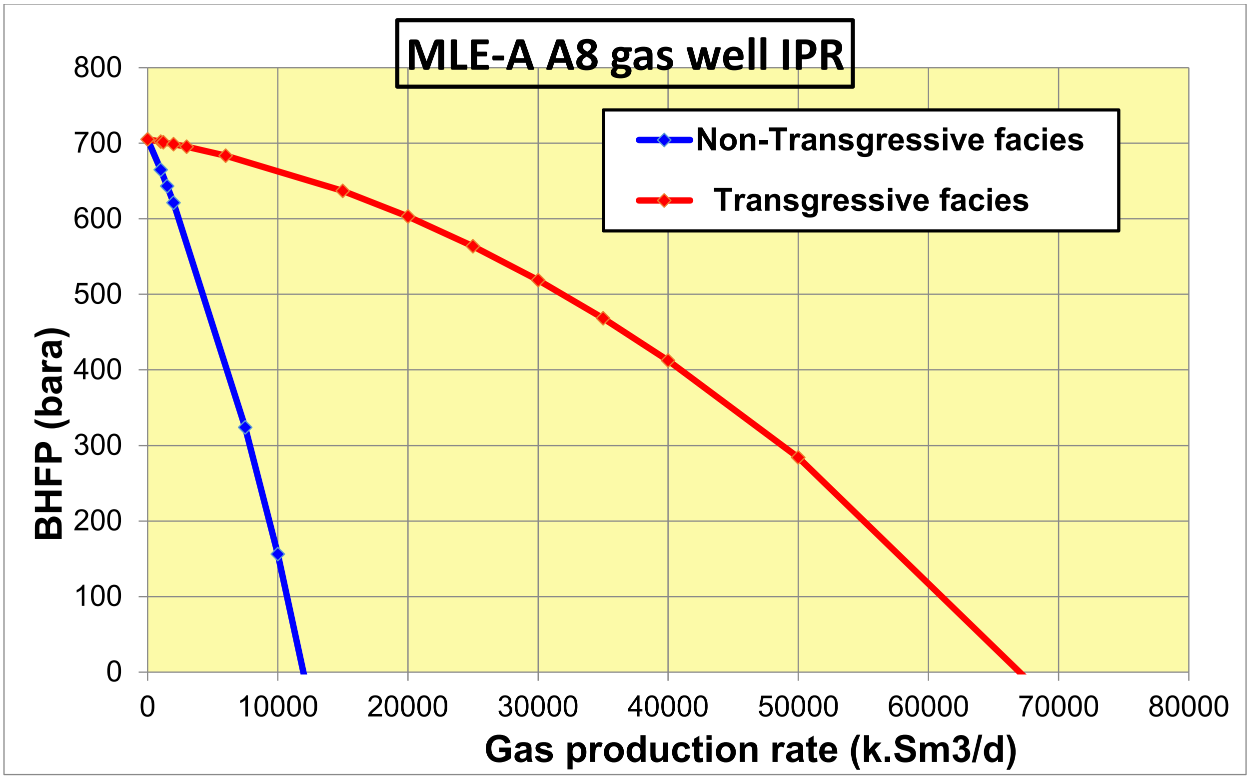

Figure 20 Expected IPR A-8

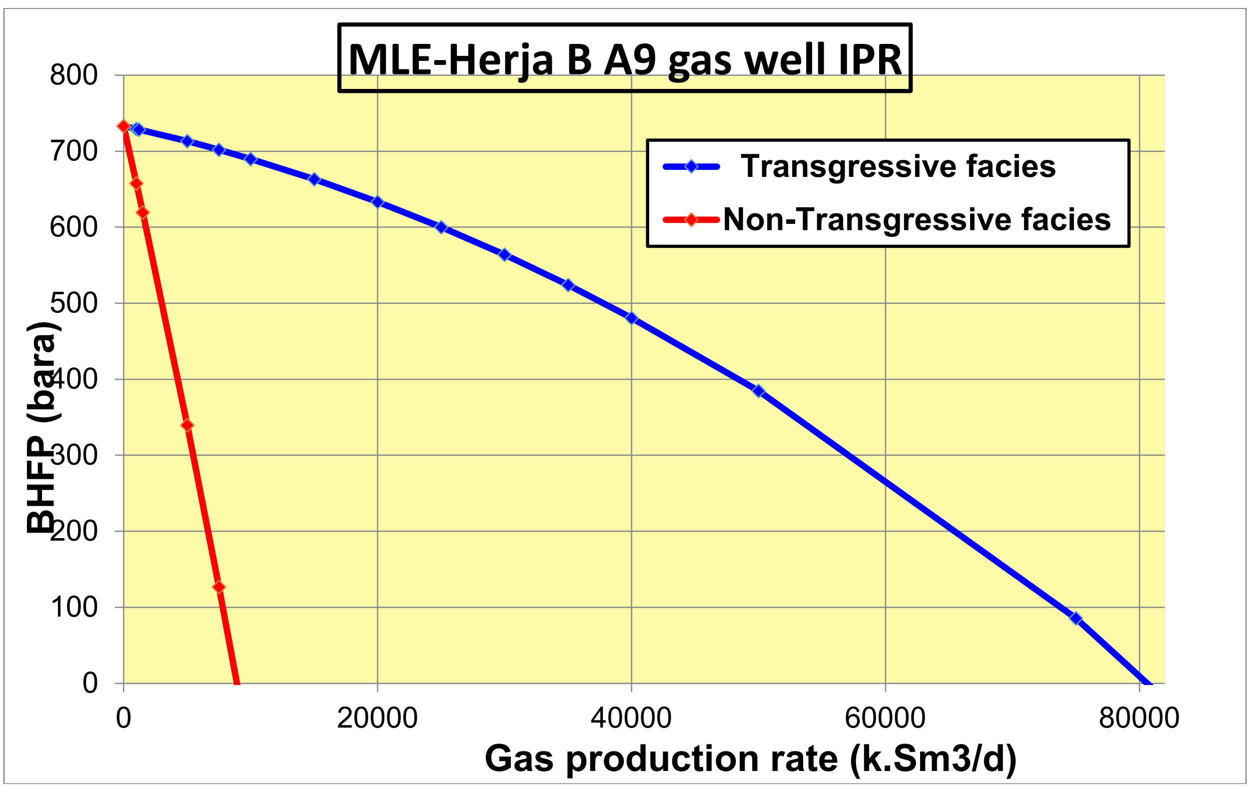

Figure 21 Expected IPR A-9

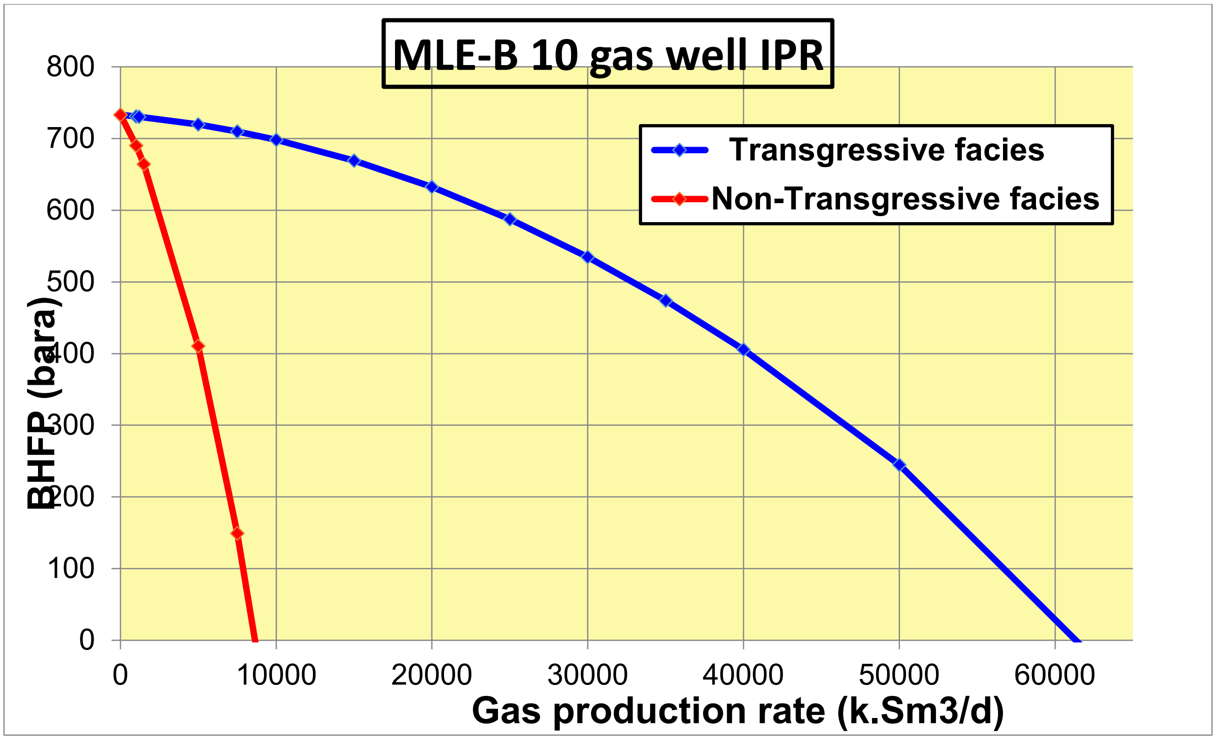

Figure 22 Expected IPR A-10

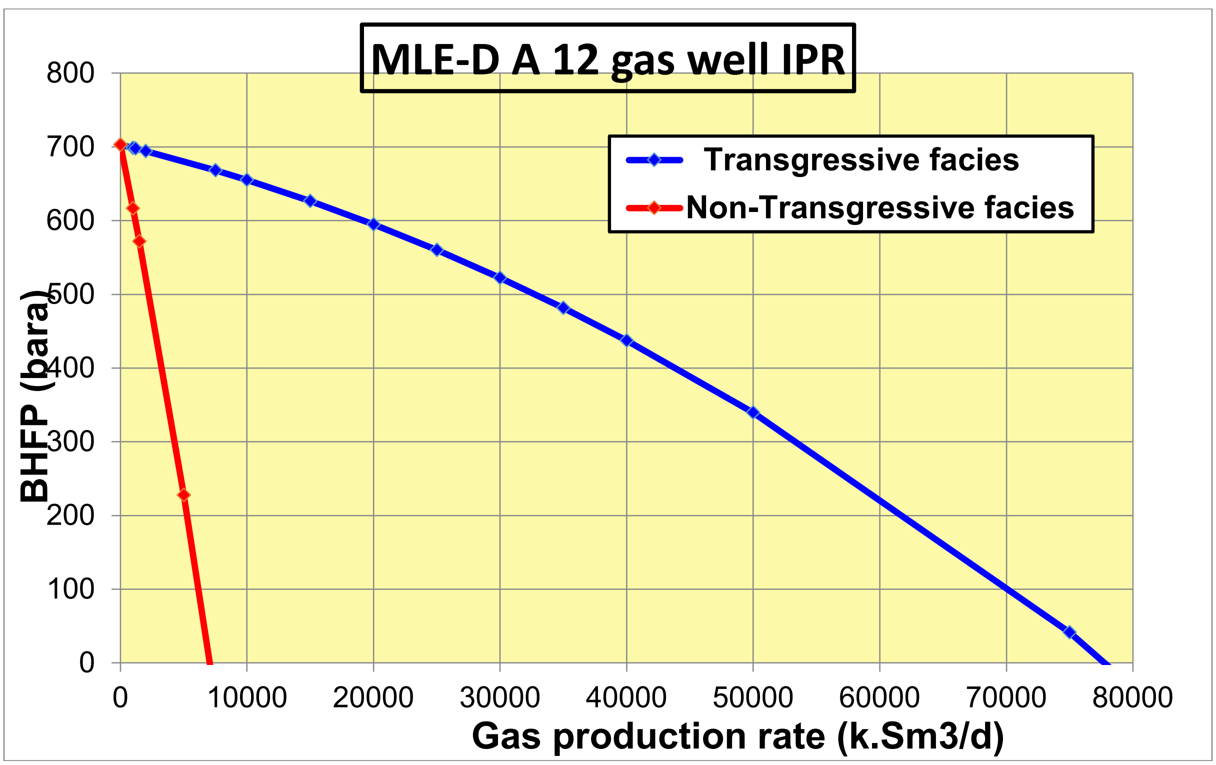

Figure 23 Expected IPR A-12

Table 9 shows the obtained PI from the real clean-up operation, except for A-10 well, due to its complications with debris/mud accumulation above glass plug which has not been cleaned yet, so it can be assumed that it will show the same PI value in the range of A-8 and A-9 well due to formation damage and usage of the equal sand control strategy i.e. ESS. For A-12 well, the well was just opened on 10th July 2017, during the preparation of this report and only the first clean-up has been completed. The value given below was asked to the person on the rig supervising the clean-up operation and since the cleanup is still running, this value will be looked upon as the final value of PI after the well is cleaned-up. Note that the PI below are based on the target gas production of 1.2 MMSm3/d in order to avoid drawdown of more 27 bar, since ESS screen will collapse if pressure differential across ESS is more than 27 bar except for well A-12 since we have used SAS screen, and with SAS we can apply higher pressure differential to obtain better clean-up.

		Expected PI			Actual PI (after clean-up)		
Brent zone	well	Pres bara	PI-gas k.Sm3/d/bar	Drawdown bar	PI-gas k.Sm3/d/bar	Drawdown bar	Qgas MM.Sm3/d
East	A-9	733	250	16	~80-100	30	1.3
East	A-8	705	281	8	~100	14.5	1.2
East	A-12	703	225	16	~200	42	1.2

Table 9 Actual PI after Clean-up

As seen from the table 9, well A-8 and A-9 shows PI almost 50% of the predicted value and it can be assumed that A-10 will show the same PI due to the use of same strategy. Well A-12 shows roughly same PI as expected, at least from first clean up and it can be assumed that it will carry on showing the same PI after the final clean-up operation.

In a proximate section, a discussion will be presented as to what could possibly be the reason that the wells with ESS screens did not show the production as expected, but similar well (A-12) completed with SAS shows good results.

3.10 Calculation Manipulation

As discussed in the lab tests section, it showed 50% permeability reduction after the tests. So assuming that RDiF (WARP) might have caused the formation damage due to invasion of micronized barite particles. Assuming it caused 50% permeability reduction, the value of permeability is reduced by half for transgressive facies to see if it gives the same PI value as seen after clean-up. The table shows new PI values after reducing permeability by 50% and it can be seen that it nearly matches the PI obtained after clean-up. PI for well A-10 is also below, as it will show the similar behavior as the other two wells due to the strategy used being the identical. One of the conclusions that can be made from this observation is that there has been severe drilling damage to the formation due to heavy WARP mud containing micronized barite. Additional facts will be presented in the discussion section to show additional reasons for low PI.

		Actual PI (after clean-up)			PI (50% Permeability reduction)	
Brent zone	well	PI-gas k.Sm3/d/bar	Drawdown bar	Qgas MM.Sm3/d	PI-gas k.Sm3/d/bar	Qgas MM.Sm3/d
East	A-9	~80-100	30	1.3	122	1.3
East	A-8	~100	14.5	1.2	136	1.2
East	A-10	235	15	1.2	132	1.2

Table 10 PI after 50% permeability reduction

Figures 24, 25 & 26 below show new PI after reducing the permeability by 50%.

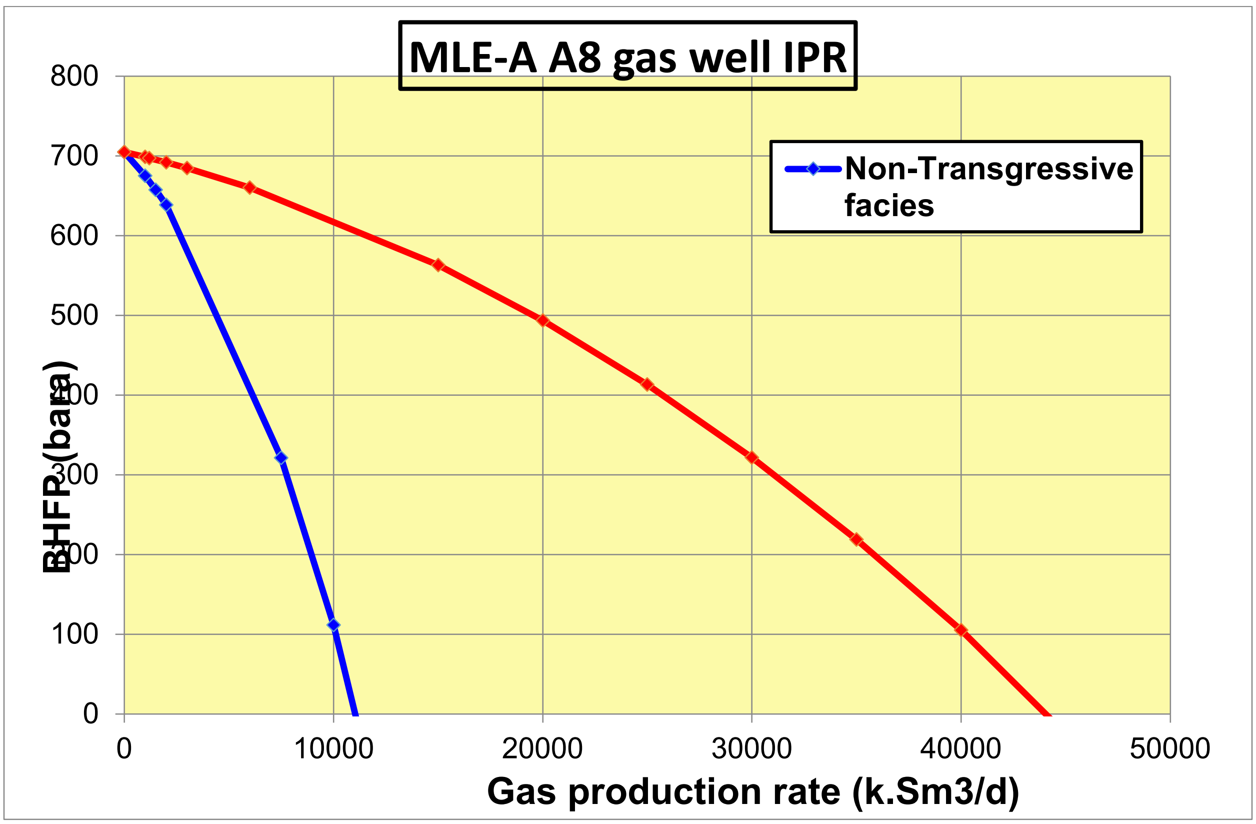

Figure 24 PI after 50% permeability A-8

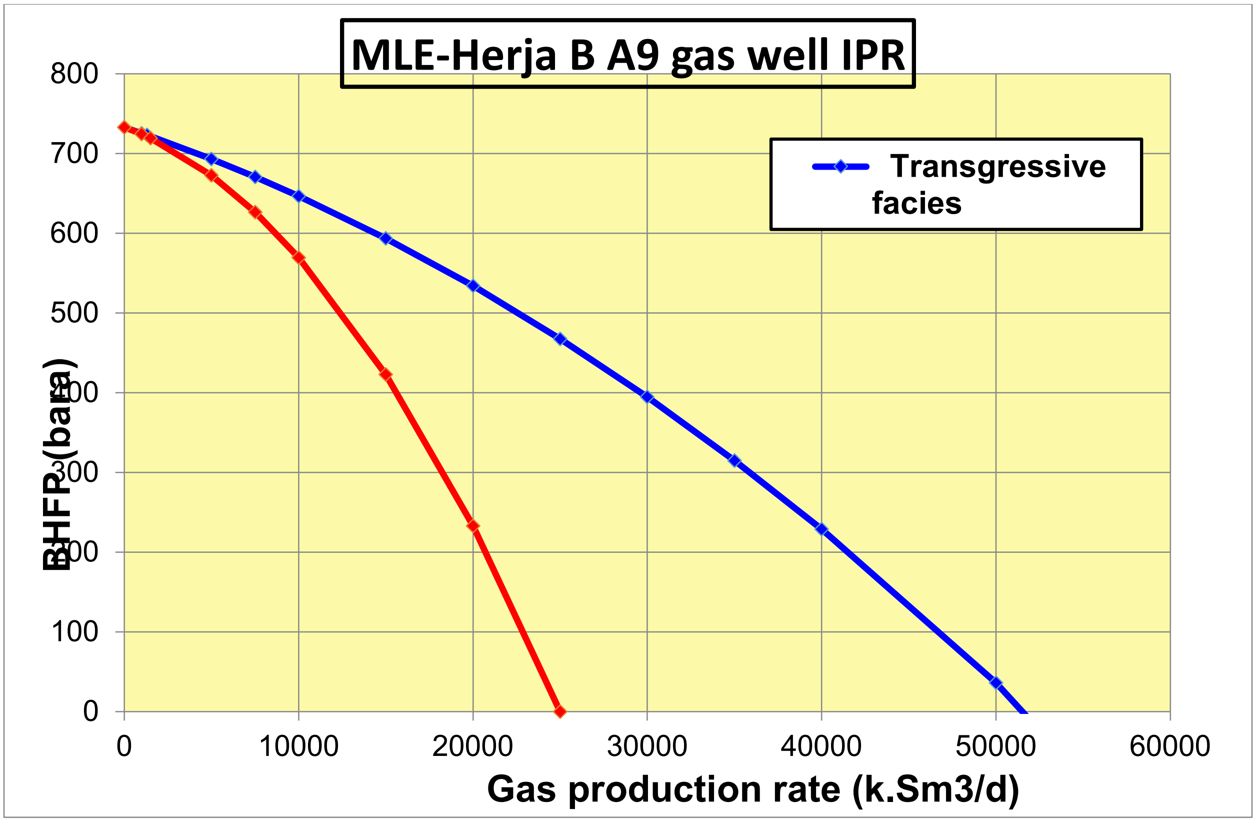

Figure 25 PI after 50% permeability A-9

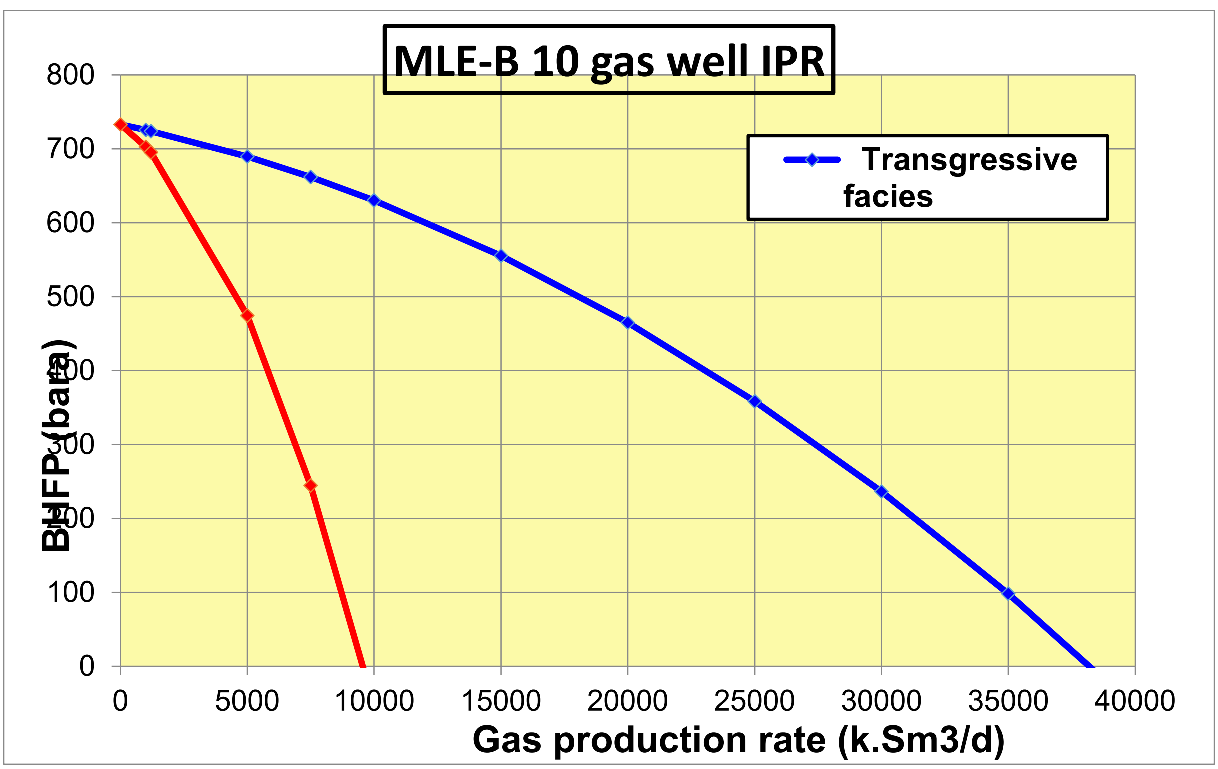

Figure 26 PI after 50% permeability A-10

4. A-12 Strategy – Changes observed

This section discusses in detail why there was an alteration in drilling and completion of A-12 after the bad experience from previous A-8, A-9 and A-12 wells.

Three producer wells A-8, A-9 and A-12 have been drilled as part of the development program of the Martin Linge Field. These wells were completed using expandable screen technology, which were expanded onto walls of the wellbore (compliantly expanded). However, unexpectedly low productivity indices (<50% compared to plan) were observed in these initial wells. It is suspected that there is impairment in the reservoir-wellbore interface of these wells. Other important reason to be believed is that in these wells, WARP oil based mud (with micronized barite as the weighting agent) was used as the reservoir drilling fluid (RDF) and Completion fluid. Since, fluid contains fine barite particles, those particles might have invaded the high permeable zones and causes significant formation damage resulting in reduced permeability.

A fourth well A-12, was planned in the development scheme and it was critical that expected production is attained by the proposed well. It was necessary that optimum reservoir wellbore interface technology for deployment was selected in very short time frame (circa ~ 2 months). The short time frame was a key constraint that clearly limited the extent of qualification that can be performed on fluids and the availability of, fit-for-purpose, permanent downhole equipment and service tools required for completion operation. But, reference to past experience from similar analogous wells proved to be successful after the well was opened on 10th July, 2017, showing good results.

The following tasks were performed before deciding new drilling/completion strategy
- Review of all previous reservoir wellbore interface related studies and recommendations.
- Evaluation of Sandface completion techniques implemented in analogous wells operated by Statoil, which shows that previous experience from the similar wells is of utmost importance.
- Re-evaluation of Sandface completion fluid.

Based on these studies it was decided to change the lower completion strategy

The recommendations were

Deployment of Stand-Alone-Screen (SAS) hardware across the Sandface [19, 20]

- Reduce risk of erosion by using screens with 6-5/8" base pipe and 250µm wire wrap screens
- Similar wells operated by Statoil and completed with SAS have shown satisfactory productivity results (Huldra field gas wells).
- Inclusion of annular barrier tools in the drain would help to curtail annular velocity

Use of Cesium Formate brine as the drilling and completion fluid [24, 28, 29]
- Minimum damage (and maximum retained permeability) is obtained when the filter cake is removed from a CS/K brine completed wellbore.
- Use of WARP OBM brings a distinct possibility of losing sand control through the creation of hotspots in the screen.
- In analogous wells operated by Statoil, wells completed with Caesium formate brine have proven to be more productive both in early and late life of well.

Since ESS completion technique failed to show satisfactory results in deliverability of well, it was necessary to access SAS and OHGP completion technique, if it would be feasible and it could provide the required results. Experience from Statoil proved to be an advantage and PSD studies as shown earlier, were used to decide size of SAS screens and quick plugging tests were performed by TOTAL to make sure that SRiF did not plug the screens. The section describes briefly the feasibility study done for OHGP and SAS.

5. Future HPHT Sand Control Selection

5.1 Comparison of OHGP vs SAS vs ESS

OHGP Feasibility
Based on OHGP simulation, gravel placement is confirmed to be possible. It was recommended that special precaution should be in place because of low fracture initiation pressure and limited industry experience of performing OHGP reservoirs requiring high density (>2.0sg) completion fluids.

The following was the issue with OHGP in Brent gas wells due to high pressure and temperature

Gravel Pack tools are available on the market. Elastomer selection should be carefully selected based on final fluid selection and mostly due to high temperature, which can be an issue.

Cesium Formate was recommended as gravel pack fluid, but industry has no experience of performing Gravel Pack with Cesium Formate 2.04 SG.

The most important point was that the window between pore pressure and fracture pressure was very small and gravel packing with heavy fluid can be risky – it can either cause a kick or loss of circulation.

Successfully implemented OHGP with no gaps or uncovered screen sections is a good antidote to erosion, as the sand particles do not have an annular space to gain velocity before hitting the screen. Even where there are gaps, the pumped gravel, serves to minimize annular flow towards the heel, in horizontal wells.

OHGP is a preferred technology for low deviation wells because, among other factors, the annular space is filled with appropriately sized sand control gravel, thereby keeping the wellbore intact without the risk of mixing sand and shale during a sand pack formation process

As per industry resources focusing on de-risking the constraints of narrow margin between pore pressure and fracturing gradient, well control / technical risks and fluids selection, OHGP was rejected. It was concluded that screened Cs/K formate can be used as a gravel pack carrier, but real time tests need to be performed in order to avoid risks with well control. Such tests may take several months (~3 months) to conclude while about six 6 months were required to order and receive appropriate permanent downhole equipment for the job. Hence, OHGP solution was rejected.

ESS Feasibility
ESS was considered to be an optimum option for previous wells due to its relative simplicity and low installation risk compared to OHGP. However, plugging of the screens coupled with weak collapse rating of expandable screen systems and the anticipated high drawdown expected

from each well would result in screen collapse and well failure. Which might be the cause of low PI's in previous wells.

Coreflood tests have been performed on a drilling fluid to determine the ease of filtercake flowback through a 230 micron ESS. For a producing well these tests involve measuring the oil permeability of a core plug, forming a mud cake on one face, inserting a section of the sand screen, and displacing the mud cake back off by flowing oil through the plug, then finally re-measuring the oil permeability. Core flood tests performed for Martin Linge with WARP mud showed positive results, but in field it failed to show the same results. So the reliability of such test possess a question.

Stand-Alone-Screen (SAS) Feasibility

Stand alone screens 250µm of wire wrap type constitutes the optimum sand control technique was the final decision.

This recommendation was further evaluated in laboratory tests where plugging tests were performed using the following fluids

- K-Formate brine and weighted with a very low particle size (D50 at 0.7µm) weighting agent
- Non-Aqueous based Mud (NABM)

The fluids were flowed through Wire wrap screens - gauge 8 and 10 openings and mesh screens with 175 and 270 µm openings range. It was observed that -

- 175 µm mesh screen plugged very rapidly, whichever mud was tested,
- lowest pressure drops with wire screens compared to meshed screens, at similar opening
- lowest pressure drops with Non-Aqueous based Mud (NABM) compared to Water based Mud (WBM)

Even though SAS has been used before in analogous fields, it was rejected for previous wells due to following reasons:

SAS wells are more prone to erosion when compared to OHGP due to two main factors

- Annular flow through the screen to areas of less resistance (typically, the heel)
- Annular space where sand grain can gain velocity before hitting the screen

Minimizing annular space is a first step to erosion control, one of the reasons why ESS was selected in the first place.

SAS Completion in low deviation (<70°) is an industry concern mainly due to potential screen plugging by shale sections falling between screen and sand in high permeable layers. Industry practice and literature on SAS performance in development wells is typically limited to horizontal wells. [52]

5.2 Statoil Experience

Statoil, a major operator in the Norwegian sector of the North Sea operates wells with similar reservoir properties as some of the Martin Linge wells under consideration.

In a review of 21 wells in 5 fields operated by Statoil, indicates that it has completed wells with varying sand face deviation (subvertical to horizontal), divers completion techniques (cemented & perforated liners, pre-drilled liners and SAS) and used different fluids to drill and complete the sand face (WARP, CS/K formate and low-solid oil based muds).

In terms of productivity, wells completed with Cs/K Formate and predrilled liners produced as anticipated, while those completed with WARP mud were up to 80% below expectation.
In terms of completion technology, no OHGP or expandable screen has been deployed in any of these wells.

Detailed outline of information gathered from the wells reviewed is shown in Table 11

In the next section, the experience from Statoil's 3 fields where Total has been the partner (Due to which it was possible to get sensitive data from Statoil), which are analogous to Martin Linge field will be outlined, so as to compare their experience with the current ML gas well strategy.

The following fields provide good correlation due to their similarity with the Martin Linge field. Especially the Huldra field provides good comparison, as A-12 well was planned on the experience from this field. This section helps us in comparing HPHT field experience with ML experience. solely key points will be summarized for comparison.

Kvitebjørn Field
Reservoir Pressure – 770 bar Temperature - 150°C

- 4 wells were completed with 6 5/8" SAS screens with 300μm (wire wrap type).
- Screens run in cesium format mud.
- Initial production was as expected with no screen plugging.
- All of the abovementioned wells show productivity according to Statoil's expectation.
- Prior to running screen, SRiF was circulated (conditioned) from 300μm shaker screens
- Wells were left suspended in Cs/K mud for 9-11 months before clean-up.
- Initial production was as expected with no screen plugging.

Field	Number of wells	Initial Reservoir Pressure	Initial Temperature	Drain length	Deviation at drain	Completion	Reservoir /Completion /Drilling fluid	Initial Productivity (as % of prognosed)	Screens Plugged?	Screen to shale isolation	Comments
Kristin	5	885	170	N/A	30-70°	SAS/PDL	WARP	10-20%	Yes	No	Only one well completed with PDL (pre-drilled liner) Up to 500 bar depletion ~0.7 NTG One well produced sand
Kvitebjørn	5	770	148	N/A	30 °	SAS / perforated liner	Cs / K Formate	90-100 %	No	No	- ~0.6 NTG - condensate blocking is a concern -over the 7 years, some wells haave up to 400 bar depletion and upto ~60% reduction in productivity
Huldra	6	600	147	N/A	Approx. 40-50	SAS	Cs / K Formate	N/A	N/A	No	4 wells currently in production 2 wells producing sand , therefore shut in
Vale	1	615	122	1035	Horizontal	SAS	1.70 LS-OBM	100	No	N/A	0.6 NTG Condensate Producer
Morvin	4	810-820	162	N/A	Horizontal	PDL	N/A	100	No	No	>0.8NTG for most wells tracers implemented and prodcution from entire drain confirmed

Table 11 Statoils experience with similar wells

Kristin Field
Reservoir Pressure – 885 bar Temperature - 170°C

- 4 wells were completed with SAS in heavy OMB (WARP).
- Deviated wells 30-40°, similar to ML gas wells.
- Initial productivity of these wells were poor, at 10-25% of expected productivity was achieved. (plugging from mud).
- OMB was replaced with Cesium Formate Cs/F after running the screens.
- Expected PI from the simulations was 1205 Sm^3/d/bar. But, after DST PI of only 405.6 Sm^3/d/bar was obtained.

If the points from Kristin field are taken into consideration, it can be observed that ML gas wells has been drilled and completed in a similar way except SAS screens, hence we can say is that use of WARP mud is not a good option in HPHT fields.

Huldra Field
Reservoir Pressure – 600 bar Temperature - 150°C

- 6 wells were completed with SAS 6 5/8" with 300µm (wire wrap type).
- Reservoir section drilled with 1.9 sg Cesium Formate Cs/K mud.
- Screens run in conditioned Cesium Formate Cs/K mud and SRiF contained 30-40 kg solids content.
- Positive and expected production from all the wells was achieved.

The Huldra gas well experience is significant as A-12 well strategy was designed based on knowledge from Huldra wells. Equal results from A-12 are expected as were obtained from Huldra wells. This comparison was to be used in this thesis if no production data was available from A-12 well, due to the same conditions would be expected as Huldra well. But, since before submission of this report the result from A-12 well first clean-up was obtained and found to be satisfactory, It can be claimed that following the same steps as Huldra has proved to be satisfactory for A-12 well, and it shows positive expectations in terms of deliverability.

Table 12 shows in short the expected and actual PI obtained from Huldra wells.

Wells	Expected		Actual	
	Rate ($MMSm^3$/d)	PI (kSm^3/d/bar)	Rate ($MMSm^3$/d)	PI (kSm^3/d/bar)
Hul A-11	2	470	1.8	450
Hul A-6	3.01	700	3	650
Hul A-8	1	230	1	210
Hul A-5	1	230	1	200

Table 12 Expected and actual PI obtained from Huldra wells.

IPR from Huldra is shown in figure 27 below

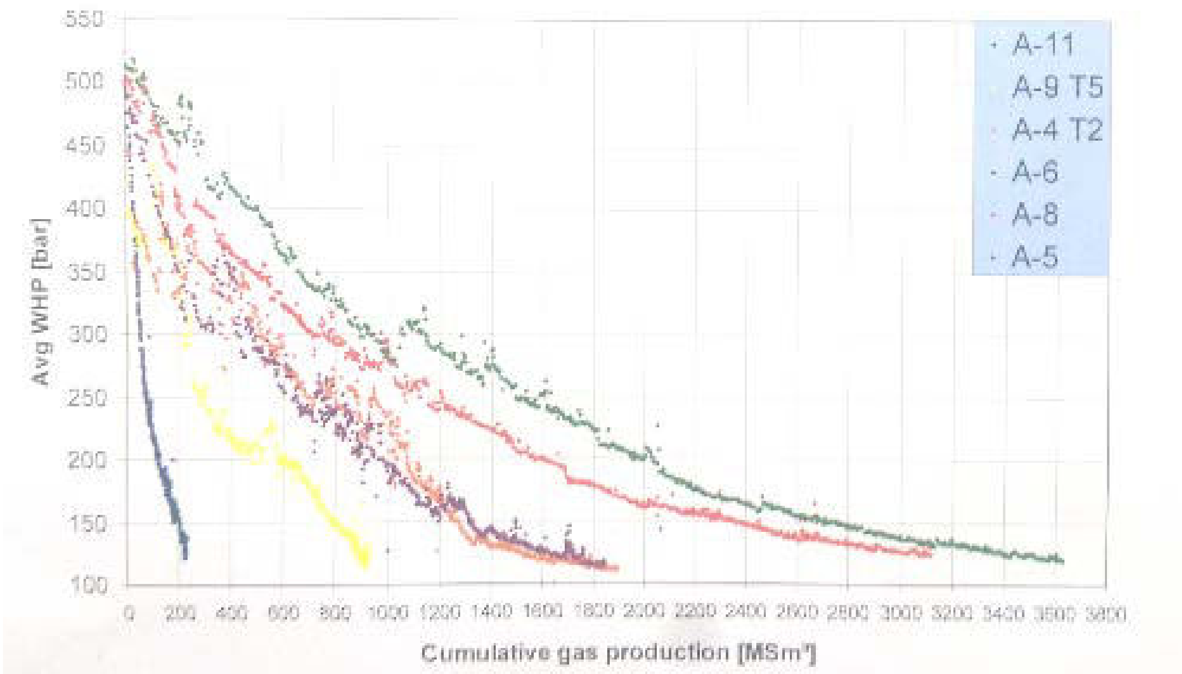

Figure 27 IPR from Huldra

Some loss in PI was observed in later life, but this is most likely due to other mechanisms, such as condensate blocking or operational failures during well completion.
For both Kristin and Huldra, the levels of sand production from the wells started at later life and insignificant. In such HPHT field wells little/zero sand production has been observed from the reservoir despite large depletion values.

Following table 13 summarizes the above field experience with Martin Linge Gas wells

Field	Fluid Type	Reservoir Temp. °C	Reservoir Press. Bar	Well Deviation	Reservoir drill-in fluid RDiF	Screen run-in fluid SRiF	Lower Completion Type
Kvitebjørn	Gas Condensate	150	770	Deviated	Cs/K formate	Cs/K formate	SAS
Kristin	Gas Condensate	170	885	30-40°	OBM (WARP)	Cs/K formate	SAS
Huldra	Gas Condensate	150	600	40-50°	Cs/K formate	Cs/K formate	SAS
Martin Linge	Gas Condensate	135	749	30°	OBM (WARP)	Cs/K formate	ESS

Table 13 Statoil field experience with Martin Linge Gas wells

5.3 Discussion

The following observations have been found during the study of this thesis.

The two RDiF / SRiF systems evaluated are:

A) WARP Non Aqueous Based Mud (NABM)
B) Cs/K Formate Water Based Mud (WBM)

The table 14 below highlights some of the identified advantages and disadvantages of the mud systems used for HPHT wells found from study of this thesis and also from industry experience [26, 27, 28]

Issue		NABM System (WARP)		WBM System (Cs/K Formate based)
Sag	-	Large solids content therefore potential sagging issues (but less sag than conventional API weighted).	+	No weighting material due to the density of the base fluid, hence no sagging issues.
Environment	+	Non-Aqueous based mud system. Cuttings have to be treated via OTCC prior discharge to sea or sent to town.	+	Less environmental impact, cuttings can be discharged to sea.
Formation Damage	+	Less theoretical damage than Cs/K Formate WBM	-	Higher theoretical damage than WARP NABM
Shale Reactivity	+	No reaction with shale.	-	Potential for shale breakouts and instability
Bridging	+	More efficient bridging due to solids laden system.	-	Higher fluid loss, less efficient bridging.
Filter Cake	-	Thicker filter cake due to high solids content	+	Thinner filter cake due to low solids content.
Viscosity	-	Higher viscosity therefore greater ECDs.	+	Lower viscosity therefore less ECD.
Lubricity	+	Higher lubricity	-	Lower lubricity
Solids Content	-	High solids content, increased chance for screen plugging	+	Low solids content, less chance for screen plugging
Reactivity	+	Low corrosion rates, less impact on elastomers.	-	Corrosion issues and elastomer degradation after exposure to Cs/K formate brines.
Well Cleanliness	-	Greater solids content resulting in more difficult well clean-out operations.	+	Low solids content resulting in simple well clean-out operations.
Logistics	+	No obstacles.	-	Limited volume available on the market
Cost	+	High cost compared to conventional NABM systems, but sustainable.	-	Extremely high unit cost

Table 14 Advantages and disadvantages of WARP and Cs/K mud system

Limitations of Laboratory Tests

These laboratory results give an indication of the interactions within the reservoir wellbore interface and the results are to be taken from a qualitative perspective. This is due to the following factors

- Tests were performed with base oil (macron-52) instead, while the actual produced fluid is natural gas and some condensate.
- An aloxite disc of representative permeability was used instead of actual cores. Therefore the effects of shale mobilization or aggregation / erosion of matrix cementing materials in the near wellbore and consequent effect(s) on final retained permeability has not be taken into account in the results presented.

Reservoir drill-in fluid

Based upon industry learning (Statoil) there is a direct correlation between well productivity and the amount of solids in the fluid system (completion fluid) during screen based RWI installation. Statoil set the absolute maximum limit at 40 kg/m^3 (0.333 lb/gal) of solids in the completion fluid during screen deployment. In case of ML wells estimated solid content in OBM RDiF was approximately 1,200 kg/m^3 (10 lb/gal) to achieve the necessary mud weight of approximately 2.03-2.04 SG. This amounts to 3000% more solids than allowable for screen deployment.

ESS Selection

This section will provide argument points supporting reduced PI in ESS completed well.

<u>Reservoir drill-in fluid</u>

As can be observed, the choice of RDiF was WARP mud containing micronized barite particles. From the experience of Kristin field, it can be argued that used of WARP mud as RDiF is not a suitable choice, although core flooding experiments show satisfactory results. There might have been invasion of barite particles during drilling and formation of thick filter cake on the wellbore wall later prevents the clean-up of this deep invaded particles.

Based upon industry learning (Statoil) there is a direct correlation between well productivity and the amount of solids in the fluid system (completion fluid) during screen based RWI installation. Statoil set the absolute maximum limit at 40 kg/m3 (0.333 lb/gal) of solids in the completion fluid during screen deployment. In case of ML wells an estimated solid content in OBM RDiF was approximately 1,200 kg/m3 (10 lb/gal) to achieve the necessary mud weight of approximately 2.03-2.04 SG. This amounts to 3000% more solids than allowable for screen deployment. So, certainly using WARP mud in high permeability zones was a bad choice.

<u>Mudcake formation</u>

Use of WARP mud containing high solid content forms a thick mud cake on the borehole wall. Tests have shown that WARP mud cake formation is sticky and around 18-20 mm, which is very thick. It can be claimed that it can be challenging to flow back such a filter cake easily and use of ESS screens put the restriction on drawdown limit (27 bars) during clean-up due to low collapse resistance of ESS. Further, high temperature can cause baking effect of filter cake making it hard and brittle and difficult to flow back during clean-up operation.

Installation of ESS

ESS installation in HPHT is now questionable after its first installation in Martin Linge field resulting in low productivity. We can conclude that ESS itself is not the sole thing that caused low productivity in the wells, but the combination of ESS, RDiF and clean-up operation can be considered as joint phenomenon in failure of ESS. Since, ESS was expanded before clean-up, one theory that can be presented is that during expansion of the screen the mud cake was pushed into the formation which caused formation damage and also this mud cake plugged the screen as screens used were mesh screens, it is possible that mud cake was imbedded in the mesh of the screen, hence during clean-up it was problematic to flow back the mud cake, which results in unsuccessful clean-up, resulting in low productivity of wells. More tests need to be run with ESS screens with different combination of RDiF formulation to assess sustainable knowledge on its ability to be used in HPHT wells. Normal test run on screen coupons shows optimistic results, but in real field condition they fail to show positive results. It is advisable to conduct tests on entire screen joint by simulating the real field condition in laboratory and then evaluating if ESS can be run into HPHT wells successfully or not. For now running ESS in real field condition is not advisable.

5.4 Future Recommendation for Martin Linge Wells

This section gives some recommendation for future sand control selection in HPHT high gas rate wells.

As part of these studies following, important points can be noted for future gas wells on Martin Linge field. Note that this information is not limited to Martin Linge field and can be successfully used for other similar fields around the world or NCS and UK shelf.

1.RDiF used as Completion fluid should be prepared in line with the following basis

Pore throat: In order to minimize depth of solids invasion it has been proven that the solids size must be tailored to the size of the pore throats of the porous network [31]. Several particles are capable of bridging over one pore throat, that is to say that the mean solid diameter (called D50) can be smaller than the mean diameter of the pore throats openings. The so-called Jamming Ratio: It is recommended to keep the jamming ratio (i.e. ratio between pore throat diameter and mean solid diameter) between 1 and 3.

$$\text{Jamming Ratio} = \frac{\text{Pore throat mean diameter}}{\text{D50 of mud solids}}$$

Screen: Mud conditioning before running the screens is the key point. As a rule of thumb (From Statoil) it is recommended to achieve a solids mean size smaller than 1/7 of screen opening (35 microns). To implement this requirement in the field, the particles should pass a Production Screen Test (PST) prior to running screens in hole, demonstrating that the brine has been well conditioned.

2.Based upon industry learning (Statoil) there is a direct correlation between well productivity and the amount of solids in the fluid system (completion fluid) during screen based RWI installation. Statoil set the absolute maximum limit at 40 kg/m3 (0.333 lb/gal) of solids in the completion fluid during screen deployment. For future wells it would be a good idea to follow this rule of thumb. In case of ML wells, estimated solid content in OBM RDiF was approximately 1,200 kg/m3 (10 lb/gal) to achieve the necessary mud weight.

3.Based upon point 2 the use of an oil based completion fluid must be ruled out due to unacceptably high volumes of solids weighting agents which would be needed to obtain the required density.

4.Irrespective of completion type, once the reservoir section has been drilled, the well must be displaced to a Water Based completion fluid. a. The preferred option would be to have a Low Solids Water Based Fluid in the open hole (to prevent / control leakage).

5.A comprehensive laboratory testing program must be established to ensure compatibility of fluid types especially during the well displacement operations which will require spacers to separate the OB and WB fluid systems to prevent mixing.

6.Operationally the ESS system option should be ruled out for time being for HPHT wells and more full screen length experiments need to carried out to determine if ESS system can be feasible in the future for HPHT wells. ESS screen plugging during installation / clean-up of the filter cake is a serious concern. Plugging of the screens coupled with the weak collapse rating of expandable screen systems and the anticipated high drawdown's expected from the wells will result in screen collapse and well failure.

7.The ability of a mudcake to be produced back through a sandscreen after installation is of concern when planning well completion strategies and mud formulation to be used for drilling reservoir section should be tested for mudcake flowback before finalizing its use to avoid later concern with screen plugging which might have been one the reason for ESS.

8.OHGP presents significant operational risks due to narrow pore/fracture pressure window, which results in

i. Risk of losses during the pumping job.

ii. Risk of early screen out and incomplete pack.

Because of the abovementioned reason, OHGP should be ruled out on future ML gas wells.

9.From Statoils experience from Huldra field and recent well A-12, SAS screen option seems to more feasible for now. SAS installation has shown to give better clean-up and expected well deliverability from both past experience and current experience from A-12 well.

10.It is necessary to build a good laboratory testing system to simulate the long term effect on filter cake due to high temperature to get a good idea about downhole behavior when well is kept suspended with fluid for several days before clan-up. It would be an excellent choice if this experiment were carried over entire screen length rather than just a small coupon sample of screens, since it can be seen that it is not a good option to rely on of traditional laboratory core flood tests, which might give optimistic results.

11. Another laboratory test that needs to be performed is the effect of temperature on the mud cake after the well is suspended for several days. We can call this phenomenon as the baking effect, as due to high temperature mud cake losses its water retention capacity and becomes hard and brittle which can be very difficult to remove during clean-up operation as it will be challenging to dissolve baked filter cake during clean-up. No literature is available on this effect of temperature on filter cake baking and studies should be performed for HPHT wells.

12.Erosion and hot spotting being the main concern of using SAS, screen can be minimized by using annular flow restrictor or ICD screens, but studies need to be performed to make sure ICDs do not cause reduce in productivity. Since, there was sudden change in strategy of A-12 there was not enough time to order and study ICD screens. But, it is advisable to do such studies for future wells to avoid erosion due to sand.

13. Since OHGP and ESS can be relevant option in the future if laboratory tests as mentioned in point 11 is planned. As the part of this thesis following flow chart has been prepared which can be used for successful selection of either OHGP or ESS if SAS option needs to be ruled out due to erosion. This flow chart can be considered a good reference for any HPHT high rate gas well sand control selection.

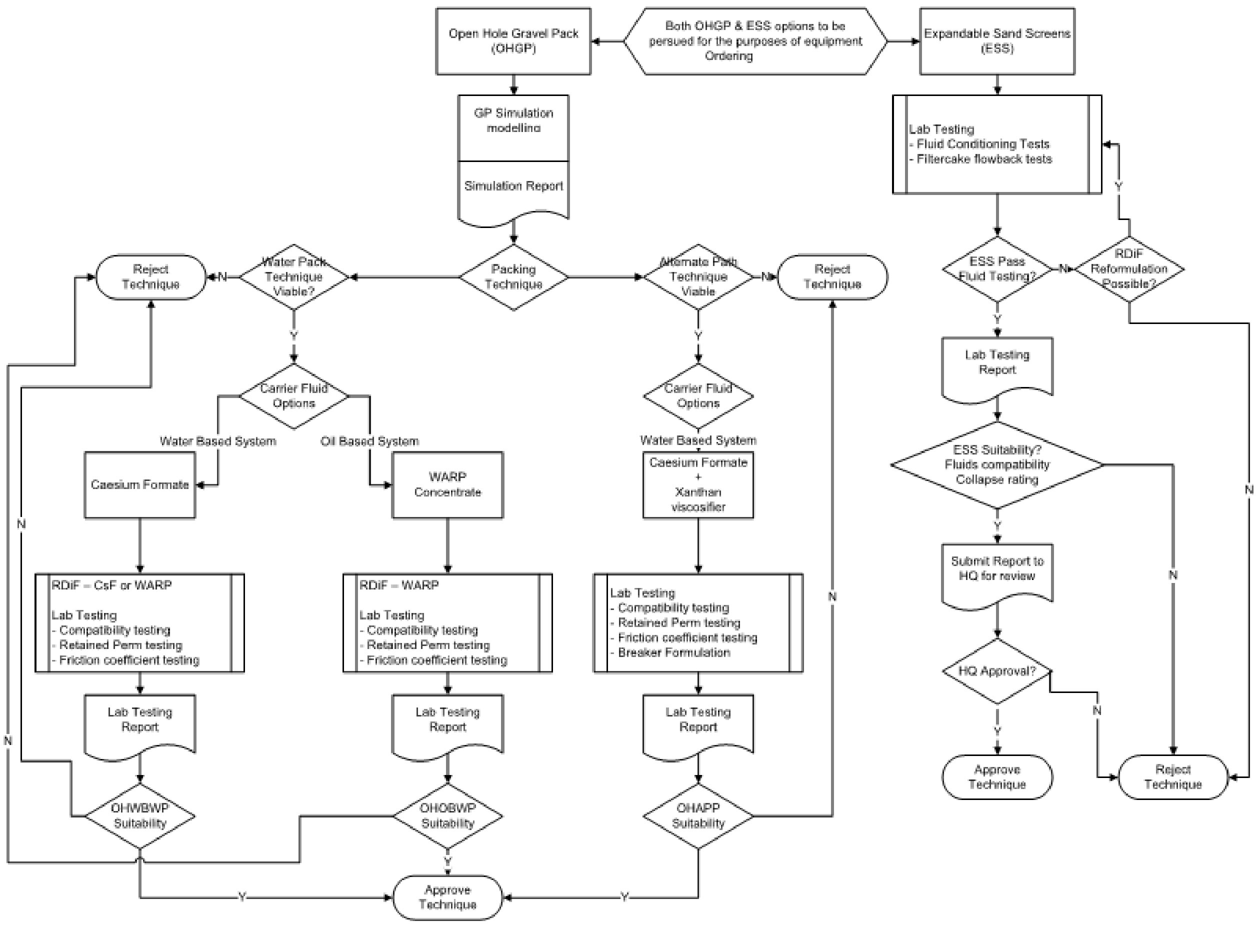

Figure 28 Sand Control Selection Flowchart

6. Conclusion

This thesis presented sand control selection in HPHT high rate gas wells completed by TOTAL in The Martin Linge filed on NCS. Three producer wells have been drilled as part of the development program in Martin Linge gas field. In these wells, WARP oil based mud (with micronized barite as the weighting agent) was used as the reservoir drilling fluid (RDF) and completion fluid. The wells were completed with open-hole expandable screen technology across the sandface with deviations ranging from 30 degrees to 40 degrees. The main objective was to evaluate the performance of ESS (Expandable sand screen) as a sand control completion used in these wells. This was the first ESS installation in HPHT field and gives us good insight into its performance on well deliverability. During tests, unexpectedly low productivity indices (<50% compared to initial plan) were observed. It is suspected that there is a major impairment in the reservoir-wellbore interface of these wells.

Calculations and simulations were done to assess the effect of ESS on skin of the wellbore. These calculations were correlated with real time data to evaluate the performance of the wells. Consequence of ESS on formation damage was also discussed. Apart from that a brief discussion was done to decide which sand control technique can provide respectable well deliverability in HPHT wells where high rate gas production can be expected. Further, this installation experience was compared to other similar fields to provide us with good correlation. As final evaluation it can be concluded that ESS have been found to be a bad choice as sand control technique in HPHT field. Low productivity were observed from the current completed wells on Martin Linge, where several factors contribute to low productivity like choice of drilling fluid with high solid content, suspension of well for long time and installation of ESS makes it worse. We know that ESS technique is not a good choice after we compared it with recently completed well in the same field, which showed expected well productivity.

It is notable that the consistently good well productivities obtained after drilling/completing with formate brines can contrast with the results of traditional laboratory core flood tests that may sometimes appear quite poor. Such a contrast brings into question the applicability and validity of the traditional laboratory core-flood test techniques that are widely used by the industry as screening tools for fluid selection. While qualifying cesium formate brine for use as a drill-in and completion fluid for the Huldra field development it was found that the formate based muds gave relatively poor return permeabilities in core flood tests that only recovered to natural levels after core-face washing with dilute organic acid. Yet, in practice, the Huldra wells all flowed at high rates without any stimulation being needed. Same can be said with respect to core flood tests performed for Martin Linge with WARP mud showed positive results, but in field it failed to show the same results.

As future work and recommendation, it is necessary to evaluate the combination of drilling and completion fluid to be used for successful application of ESS in HPHT fields. Several suggestions were made to carry out tests with full ESS joints where real field conditions can be simulated, since currently carried out traditional test show optimistic results and fail to show the same results in real field conditions. It was also discussed that not only selection of appropriate sand control technique is essential, but the use of drilling and completion fluid also plays a central role in combination to the selected technique. All these parameters are of utmost importance due to the fact that millions of dollars are invested in developing a single well, and it is an economic essential that the well performs in a satisfactory way in terms of deliverability.

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