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Completion Design Review with Focus on Well Integrity and Productivity

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Background:

Wells drilled in HPHT formations experience severe stress because of the extreme temperatures and pressures. This has a major effect on the completion design and the equipment that is exposed in the well. Finding the right design for the well plays an important role for the well integrity.

Task:

1) Review completion design for the subsea HPHT Morvin Field
2) Invesitgate loads on tubular string, and loads transferred from the string to the packer
3) Discuss the well integrity and possible leak development during the lifetime of the field.

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Michael Golan

Preface

This project has been carried out at the department of Petroleum Engineering and Applied Geophysics at the Norwegian University of Science and Technology as the final part of a Master degree in Petroleum Technology.

I would like to use this opportunity to thank Professor Michael Golan for proposing this thesis and guidance at the end of the work.

A deep gratitude goes to Bjørn Brechan, my main supervisor at NTNU. I would like to thank him for all the training I got in the use of Wellcat™, all the input data he has supplied and all the knowledge he has shared. I could not have had a better supervisor.

And last, but not least I would like to thank all of my friends at the study room who have made the days fly by with lots of laughter and card games.

Trondheim, 11.06.2012

Karianne Skårnes Vågenes

Samandrag

I denne avhandlinga har eit fullt brønndesign og detaljert produksjonsrøyrdesign blitt utvikla for HPHT brønnen K-14. Wellcat ™ foringsrøyrdesign programvare har blitt brukt for røyrstrenganalyser.

K-14 er utforma etter de same vilkåra som for Morvin HPHT. Dei viktigsate spørsmåla knytt til denne spesifikke brønndesignen er fullføringa av reservoarseksjonen, produksjonsrøyrdesign med tilhørande lastar, slangen design med alle relevante lastar, og HPHT brønndesign utvikla med tanke på fleksibilitet for intervensjon og mogleg stimulering ved hjelp av hydraulisk oppsprekking.

Dreneringsplanen til reservoaret er basert på brønnar med horisontale reservoarseksjonar for optimal og kostnadseffektiv utvinning.

Produksjonsrøyret har blitt designa og konstruert for alle lastane brønnen kan bli utsatt for i løpet av levetida. Det er svært viktig at alle moglege lastar har blitt undersøkt, slik at brønndesignet er i samsvar med krava for ein HPHT brønn. Dei lastene som brønnen ser kan delast i to grupper: lastar forårsaka av produksjon og laster relatert til installasjon (kvalifikasjon / trykktesting) og intervensjon.

Fokuset for dette brønndesignet har vært å oppnå optimal drenering med ei enkel og fleksibel løysning for å møta krava som er satt for intervensjon.

Ekstreme belastingar kan oppstå for brønnar i HPHT felt. Det er fleire aspekt å ta hensyn til når ein skal designa brønnar av denne typen, som for eksempel stål og stoff degradering når dei blir utsett for høge temperaturar, og store temperatursvingingar frå varm produksjonsstraum, til bullheading med kalde væsker. Effekten av ekstreme temperaturendringar som blir sett av væsker i det lukka ringrommet, og vil føre til utviding/ samantrekning som resulterer i en auke / reduksjon i trykk sett av røra. Temperaturvariasjonar vil også påverke pakningar som er under høgt trykk, noko som kan gjera materiale sprøtt og redusere / mista tettingskapasiteten.

Aspekt som påverkar brønndesign og produksjonsrøyrdesign er diskutert i detalj gjennom utvikling av HPHT brønn K-14.

Abstract

In this thesis a full well design and detailed tubing design has been developed for the HPHT well K-14. Wellcat™ casing design software has been used for tubing string analysis.

K-14 has been designed using the same conditions as for wells in the Morvin HPHT field. The main issues related to this specific well design are the completion of the reservoir section, the tubing design with all relevant loads, and a HPHT well design with flexibility for intervention and stimulation by hydraulic fracturing.

The reservoir drainage plan is based on wells with horizontal reservoir sections for optimal and cost effective recovery.

The tubing has been designed and engineered for all the loads that the well may be exposed to during its lifetime. It is very important that all possible loads have been investigated, so the well complies with the HPHT requirements. The loads seen by the well can be divided in two groups: the loads induced by production and the loads during installation (qualification/pressure testing) and intervention.

The focus of the well design has been to achieve optimal drainage with a simple and flexible solution to meet the requirements for intervention.

Extreme loads may occur for wells in HPHT fields. There are additional aspects to consider when engineering these wells, such as steel and material degradation when exposed to high temperatures, and large temperature variations from production to bullheading with cold fluids. The effect of extreme temperature changes are seen by the liquids in the closed annuli, they will expand/contract resulting in an increase/decrease in pressure seen by the tubulars. The temperature variations will also affect sealing elastomers that are under high pressures, making them brittle and reduce/loose the sealing capacity.

The aspects of well design and tubing design are discussed in detail through the development and engineering of the HPHT well K-14.

Table of Contents

PREFACE .... **III**

SAMANDRAG .... **V**

ABSTRACT .... **VII**

TABLE OF CONTENTS .... **IX**

LIST OF FIGURES .... **XIII**

LIST OF TABLES .... **XV**

1 INTRODUCTION **1**

2 INPUT DATA **3**
- 2.1 PORE PRESSURE, FRACTURE PRESSURE AND TEMPERATURE 3
- 2.2 RESERVOIR FLUID 3
- 2.3 WELL PATH 3
  - *2.3.1 Dogleg Severity* *4*
- 2.4 WELL K-14 – CASING PROGRAM 5
- 2.5 MATERIAL SELECTION 6
  - *2.5.1 Corrosion* *6*
  - *2.5.2 Safety and design factors* *7*
  - *2.5.3 Material degrading due to temperature deration* *8*
  - *2.5.4 Casing wear allowance* *8*

3 COMPLETION AND WELL DESIGN – K-14 .... **11**
- 3.1 WELL DESIGN – COMPLETION OF THE RESERVOIR SECTION 11
- 3.2 MORVIN OPEN HOLE COMPLETION 12
- 3.3 PERFORATING 13
- 3.4 TUBING SELECTION 14
- 3.5 INTERVENTION 14

4 WELL INTEGRITY **15**
- 4.1 LOADS 15
- 4.2 CORROSION AND EQUIPMENT WEAR 15
- 4.3 BARRIER DESIGN 16
  - *4.3.1 Casing program* *16*
  - *4.3.2 Cement* *16*
  - *4.3.3 Barrier envelope* *16*
- 4.4 K-14 WELL INTEGRITY 17
- 4.5 PLUG AND ABANDONMENT 19
- 4.6 OTHER 20

5 K-14 STRESS ANALYSIS 21
5.1 LOAD PRINCIPALS 21

6 RESULTS 23
6.1 TUBING RESULTS 23
6.1.1 Design limit plot 23
6.1.2 Differential Pressure 24
6.1.3 Internal pressure 25
6.2 CASING RESULTS 26
6.2.1 Design Limit Plot 26
6.2.2 Differential pressure 29
6.3 PACKER RESULTS 31
6.3.1 Tubing to packer forces 32
6.4 HYDRAULIC FRACTURING 34
6.4.1 Parameters 35

7 DISCUSSION 39

8 CONCLUSION 41

9 FURTHER WORK 43

10 NOMENCLATURE 45

11 WORKS SITED 47

APPENDIX 51
A.1 ELEMENTS IN FIELD DEVELOPMENT 51
A.2 GAS COMPOSITION 55
A.3 CASING DESIGN 56
A.4 MECHANICS 57
A.4.1 Axial Loads 57
A.4.2 Hydrostatic Forces 57
A.4.3 Hooks Law 57
A.4.4 Neutral stability point 58
A.4.5 Ballooning 59
A.4.6 Temperature 60
A.4.7 Buckling 61
A.4.8 Burst 63
A.4.9 Collapse 64
A.4.10 Triaxial 65
A.5 WELLCAT™ 67
A.6 LOADS 69
A.6.1 Clean up – first flowing of the well 69
A.6.2 Early life production 70

A.6.3 Shut in Short *71*
A.6.4 Shut in Long *71*
A.6.5 Bullheading *72*
A.6.6 Kill operation *73*
A.6.7 Breakdown *74*
A.6.8 Fracturing *74*
A.6.9 Annulus Active *75*
A.6.10 Initial Conditions *76*
A.6.11 Pressure Test *76*
A.6.12 Tubing Leak *77*
A.6.13 Tubing Evacuation *78*
A.6.14 Mini-fracturing *78*
A.6.15 Screen out *79*
A.7 PACKER 80
A.8 WELL INTEGRITY 84
A.9 STIMULATION FLUIDS 86

List of Figures

Fig.- 1-1 Elements in field development. 1
Fig.- 2-1 3D-well design for K-14. 4
Fig.- 2-2 Dogleg severity. 5
Fig.- 2-3 Mud window™. 5
Fig.- 2-4 Casing wear allowance, 5" production liner. 9
Fig.- 2-5 Casing wear allowance, 7" production liner. 10
Fig.- 2-6 Carsng wear allowance, 9 5/8" casing. 10
Fig.- 3-1 Crosssection illustrating perforating through damaged zone [Schlumberger 2012 B]. 11
Fig.- 3-2 Pressure gradients for the lower section of the Morvin well. 12
Fig.- 3-3 Well schematic. Left: K-14. Right: Morvin, modified from [Fitnawan et al. 2011]. 13
Fig.- 4-1 Primary and secondary well barrier during production, modified from [NORSOK D-010, 2004]. 18
Fig.- 4-2 Well barrier schematic for permanent abandonment - perfortated well [NORSOK D-010, 2004]. 19
Fig.- 5-1 Pressure acting on casings, tubing and packer. 22
Fig.- 6-1 Design limit plot, tubing. 24
Fig.- 6-2 Differential pressure, tubing. 25
Fig.- 6-3 Internal pressure, tubing. 26
Fig.- 6-4 Design limit plot, 5" Production Liner. 27
Fig.- 6-5 design limit plot, 7" liner. 28
Fig.- 6-6 Design limit plot, 9 5/8" casing. 28
Fig.- 6-7 Differential pressure, 5" production liner. 30
Fig.- 6-8 Differential pressure, 7" production liner. 30
Fig.- 6-9 Differential pressure, 9 5/8" casing. 31
Fig.- 6-10 Production packer, drawing no. A28-993-00 [Baker Oil Tools 2008]. 31
Fig.- 6-11 Packer envelope; 1-Annulus active, 2-Breakdown, 3-Tubing leak below tubing hanger, 4-Tubing evacuation. 33
Fig.- 6-12 Tubing-to-packer force, Tubing evacuation. 34
Fig.- 6-13 Bullheading and fracturing, WHP and BHP. 35
Fig.- 6-14 Maximum fracture pressure for tubing, 1150 bar. 36
Fig.- 6-15 Design limit plot - Fracture fluid temperatures. 37
Fig.- 6-16 Tubing-to-Packer force, fracturing base case. 38
Fig.- 6-17 Tubing-to-packer force, Fracturing at 100 °C. 38
Fig.- 1-1 Marine seismic acquisition [Schlumberger 2012 A]. 51

Fig.- 1-2 Seismic model [British Geological Survey 2012]. 52
Fig.- 4-3 Neutral stability point, modified from Wellcat™. 59
Fig.- 4-4 Ballooning and Reverse Ballooning 60
Fig.- 4-5 Tubing cross section. 62
Fig.- 4-6 Stress components of triaxial analysis. 65
Fig.- 4-7 Design limit plot. Modified from [Bellarby, 2009]. 66
Fig.- 7-8 Production packer, drawing no. A28-993-00 [Baker Oil Tools 2008]. 81
Fig.- 7-9 Tubing-to-packer forces, modified form Wellcat™. 82
Fig.- 9-10 Boric acid cross-linking of guar gum for hydraulic fracturing fluids [Barron 2011]. 86

List of Tables

Table 2-1 Casing and Tubing Configuration, Wellcat™. 5
Table 2-2 Ratings for tubing and connections [Vallourec Mannesmann Oil & Gas 2008]. 7
Table 2-3 Design parameters. 7
Table 5-1 Simulated load cases. 21
Table 6-1 Tubing-to-packer forces. 32
Table 6-2 Pressures for different fracture fluid densities. 35
Table 2-1 Gas Composition 55
Table 4-2 Requirements for buckling. Modified from [Bellarby, 2009]. 63

1 Introduction

Field development often start with evaluation of the size of the reservoir, how much it will produce for how long, how many wells are needed and how much each well has to produce. An overview of the steps required for field development is presented in Fig.- 1-1.

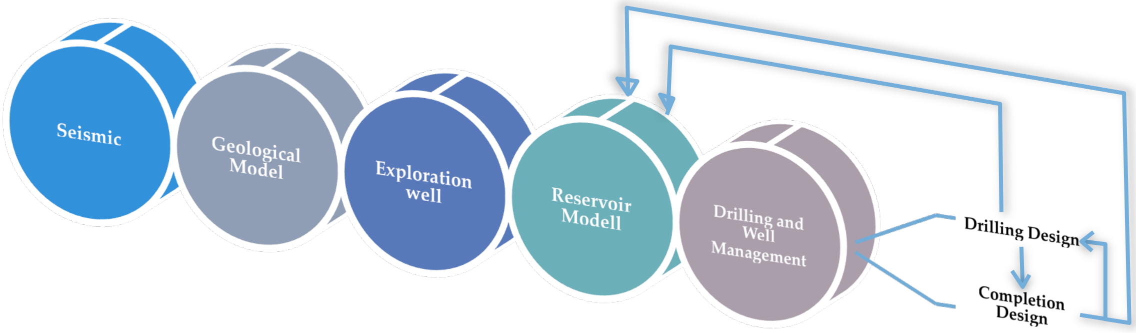


Fig.- 1-1 Elements in field development.

From a completion design perspective, the tubing size is often determined by the planned production rate. The tubing size may be restricted by the loads it is exposed to. If high grade and/or thick tubing walls cannot manage these, the size must be reduced which will influence the maximum production rate of the well. The casing design must be made to accommodate the tubing, so the casing design often starts with the requirements to reservoir section size and tubulars large enough for the planned tubing.

The design software that has been used to engineer the loads seen by the tubing and production packer is Wellcat™ by Landmark.

For the completion and well design for K-14 the focus has been to keep the design as simple as possible to eliminate the possibility for failure and minimize the possible leak paths. The production packer has been placed in 9 5/8” casing to allow perforation in the 7” liner.

The definition of a typical HPHT well is that the minimum true vertical depth is 4000 m, and/or that the shut in wellhead pressure is greater than 690 bar and/or bottom hole temperature is greater than 150 °C. [Fitnawan et al. 2011]

The input parameters for the well design of K-14 are detailed described in Chapter 2 and a closer description of the different loads are described in Appendix A.6.

2 Input data

2.1 Pore pressure, Fracture pressure and Temperature

K-14 is based on similar conditions as the high pressure-high temperature Morvin field located in the North Sea. The top of the reservoir is located at 4500 m depth reaching down to 4700 m, consisting of two productive sandstone zones separated by a tight shale. The water depth is approximately 350 m and the air gap is 25 m. This gives a pressure of 790 bar at the top of the reservoir which increase to 837 bar at the bottom. The overburden gradients and the formation fracture pressure have been determined so that the well will be similar to already existing HPHT wells at Morvin.

The temperature gradient of the field is assumed to be 3,65 °C/100 m, and given a seabed temperature of 4°C the temperature at the top of the reservoir will be 154 °C. For the simulations done in Wellcat™, the temperature used is the one located at the bottom of the perforations. This is at 6004.56 m measured depth and the temperature is 162.5 °C. That the temperature gradient is a linear function relative to the depth is not scientifically correct. In reality, the temperature will wary with the type of formation and its rate of compaction. It is reasonable to expect a greater temperature decrease at sealing formations with low heat conductivity.

2.2 Reservoir fluid

The initial production rate is set to be 1100 m^3/day and has a GOR of 465 m^3/m^3. The oil has an API gravity of 32 and the gas has a gravity of 1.321 kg/m^3, this gives a total density of 632 kg/m^3. The gas composition is listed in Appendix A.2. It is the mixed composition from all the producing zones that have been included in the load evaluations. The field will be produced by natural pressure depletion, the only injection into the well will be in terms of well control, stimulation or chemical treatment.

2.3 Well path

Detailed description of the well path is given by the survey generated for K-14. Information like measured depth, true vertical depth, inclination, direction and dogleg severity provides the input values for the following well design.

The well has been drilled as a deviated well with an inclination ranging from 43 ° when entering the reservoir to 90 ° at the end of the well. This is designed to maximise the production rate and to delay water breakthrough. The well path for K-14 is shown **in** Fig.- 2-1.

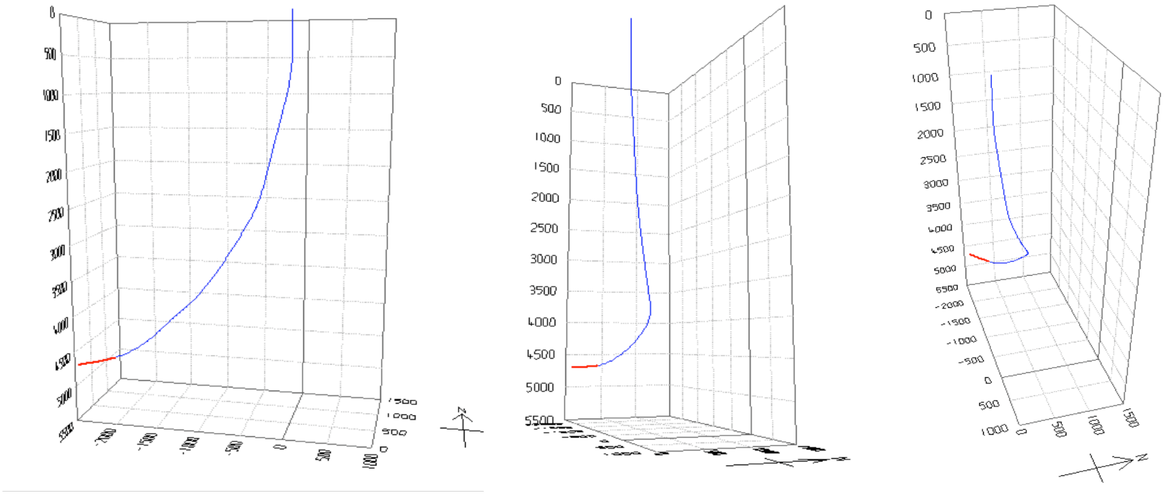


Fig.- 2-1 3D-well design for K-14.

2.3.1 Dogleg Severity

The dogleg severity profile of the well is given by Fig.- 2-2, and as seen it is not high in any point in the well. This means that there is no particularly place in the wellbore where the direction of the well path changes sharply. This means that the tubing will not suffer severe bending forces due to dogleg severity. Wellcat™ incorporates the DLS to the calculations. To accommodate for the difference between planned well path and the real (often less smooth than the planned), Wellcat™ allows for an error margin. Dogleg severity override will lead to calculations being performed with higher DLS than the DLS in the theoretical plan.

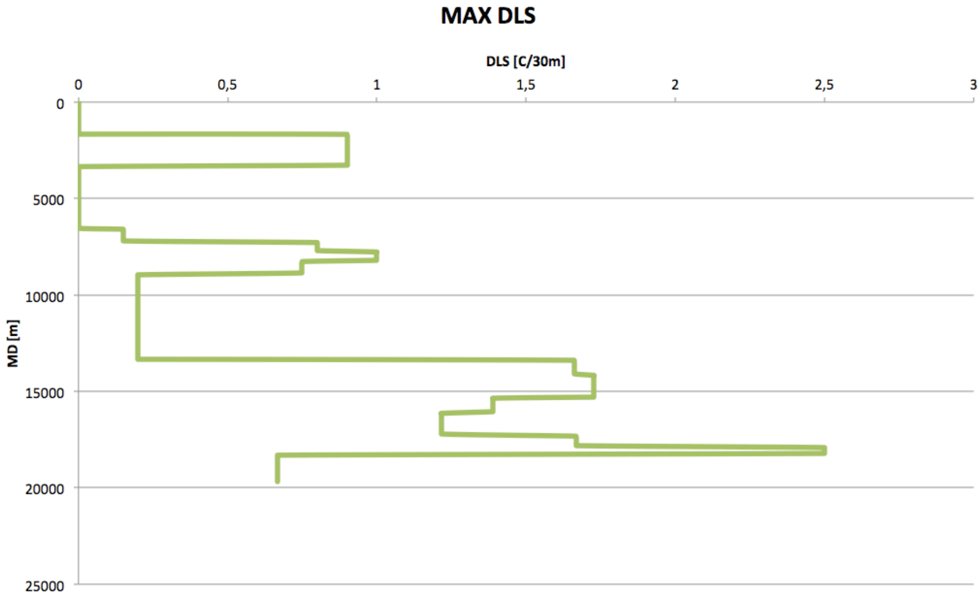


Fig.- 2-2 Dogleg severity.

2.4 Well K-14 – casing program

Casing setting depths have been chosen based on Fig.- 2-3 below. The casing and tubing design chosen is shown in Table 2-1, and is identical to the input values in Wellcat™.

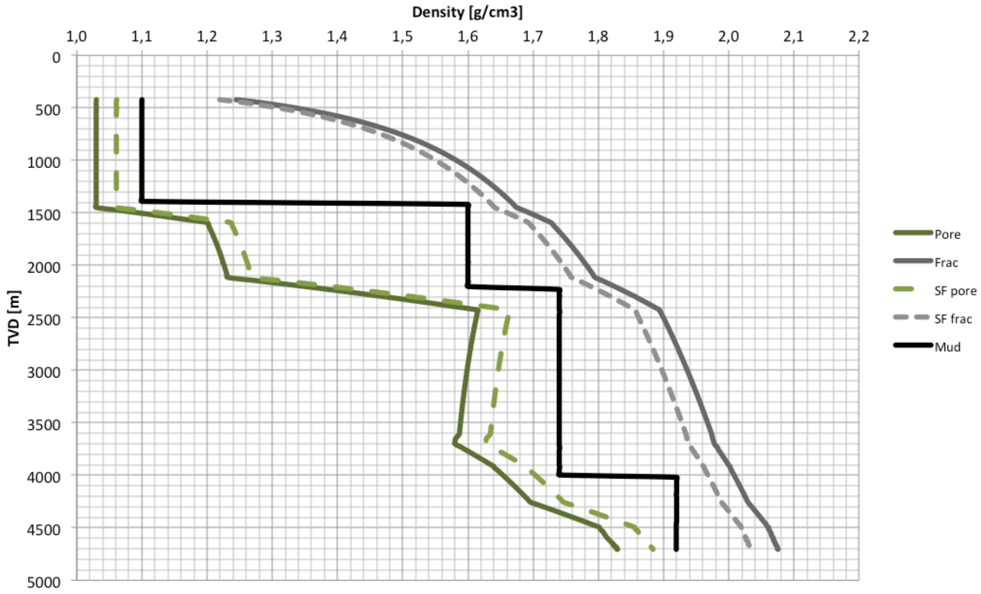


Fig.- 2-3 Mud window™.

Table 2-1 Casing and Tubing Configuration, Wellcat™.

Name	Type	OD (in)	Hanger (m)	MD (m) TOC	Base (m)	Hole size (in)
Conductor	Casing	30	374.90	374.90	479.76	36
Surface	Casing	20	374.90	374.90	1390.19	26
Intermediate	Casing	13 3/8	374.90	1725.00	2200.96	17 ½
Production	Casing	10 ¾	374.90	2900.00	3996.23	14 ¾
Production	Liner	7	3846.27	3846.27	4458.92	8 ½
Production	Liner	5	4159.00	4159.00	4703.06	7 7/8
Production	Tubing	5	374.90		4156.86	

The production packer is set at 3796 m, sealing off the annulus between the production tubing and the 9 5/8"production casing. The TRSCSSV is installed at 525 m.

2.5 Material selection

2.5.1 Corrosion

When selecting steel type for pipes and connections it is important to also consider the corrosive environment that the steel will be subjected to. There are several parameters in the well that effect the corrosion, like temperature, chloride ion concentration, partial pressure of CO_2 and H_2S, pH and presence or absence of Sulphur [Craig et al. 2011]. When selecting a material there are certain aspects that has to be taken into consideration [NORSOK M-001 2004]:

- Corrosivity;
- Design life;
- Availability;
- Failure possibility, and the consequences related to failure;
- Resistance to brittle fracture;

The steel selected for the pipe and connections, for 5" liner and for 5" tubing, are carbon steel super 13% Cr-110. Carbon steel is known to have a low corrosion allowance of 3 mm, and the corrosion rate can be as low as 0.1 mm/year with injection of inhibitors. The super 13% chrome alloy plays an intermediate role between the conventional 13% Cr and duplex stainless steel, both when it comes to corrosion resistance and material cost. For the simulations in Wellcat™, corrosion has been taken into consideration, and a minimum wall thickness has been identified as a tolerance limit.

2.5.2 Safety and design factors

When selecting the tubing material it is important to consider that is should be able to withstand a certain load. Safety factors are used to compare the rating of the material to the actual load, and this can be calculated for each type of failure as in **Eq.** (2.1).

$$SF = \frac{Rating}{Load} \tag{2.1}$$

The material selected for the tubing is shown in table Table 2-2, and the safety factors are calculated based on these ratings and the load conditions simulated in Wellcat™.

Table 2-2 Ratings for tubing and connections [Vallourec Mannesmann Oil & Gas 2008].

	5" Tubing Crs-110	**™Vam TOP HT Connection**
Yield Strength [kN]	3388	3322.8
MIYP [bar]	1148.7	1268.6
$P_{collapse}$ [bar]	1199	-

If the safety factor is greater than 1, the tubing should stay intact. This is the case if all calculations are correct, loads scenarios are recorded accurately and that the manufactured pipes behave according to its specifications when it is in the well. The safety factors that are used are often higher than 1 to account for any uncertainty [Bellarby, 2009]. The design parameters that are entered into Wellcat™ are displayed in Table 2-3. They have been selected based on general completion design factors.

Table 2-3 Design parameters.

	Axial	**Burst**	**Collapse**	**Triaxial**
Pipe body	1.3	1.1	1	1.25
Connections	1.3	1.1	-	-

2.5.3 Material degrading due to temperature deration

As the temperature in the well increase, the steel and CRA strengths decrease. Because of temperature variation along the length of the tubing string, the amount of strength degradation depends on the location in the well [Banon et al. 1991]. For the simulations done in Wellcat™ temperature profile is given and the temperature of the fluids injected is taken into consideration.

2.5.4 Casing wear allowance

The casing is exposed to mechanical wear when drilling the following sections, when installing tubing/liner and under well intervention. When drilling the horizontal section the drill bit and drill string will be, due to gravity, drawn to one side of the casing that is being drilled through. Casing wear can be affected by casing grade, rotation of drill bit, type of drilling fluid, dogleg severity, inclination etc [Directive 010 2009].

The sections that are most exposed for this are 9 5/8″ casing and 7″ liner. The wear will weaken the material because of the reduction of wall thickness. The casing wear allowance is a prediction of the percentage of the wall thickness that can be worn away, without having consequence for the integrity of the pipe. The CWA has been estimated for 5 ″ liner, 7″ liner and 9 5/8″ casing, based on the qualification needed for the simulated service loads and the pressure test of the well.

5″ - Production Liner

The maximum casing wear allowance for the 5″ production tubing is shown in Fig.- 2-4 and is 29.28 %. This is estimated for the pressure test since this is the highest load the well will see, for all other loads the CWA will be higher.

7″- Production Liner

The maximum casing wear allowance (Fig.- 2-5) for the 7″ liner is 14.16 % for the pressure test load. Pipe grade of this liner (Q-125) is lower than for the 5″ liner, this is why the CWA is so much lower. It is a question related to the actual needs of the section and economy that has to be considered when selecting a higher pipe grade. It is not expected major casing wear for this section because of the short distance that have to be drilled for the 5″ section, therefore the 14.14 % CWA is acceptable.

9 5/8” – Production Casing

The pipe grade first used for this section was the same as for the 7” liner. This leads to a CWA of 0 %. The pipe grade needed to be increased to a more durable one, and Q-125 was selected. The CWA for this grade is 28.48 % at the bottom of the section (Fig.- 2-6). The CWA is quite low at the top (4.27 %), but since this part in not exposed to the pressure test, the pipe grade has not been changed in that part of the casing.

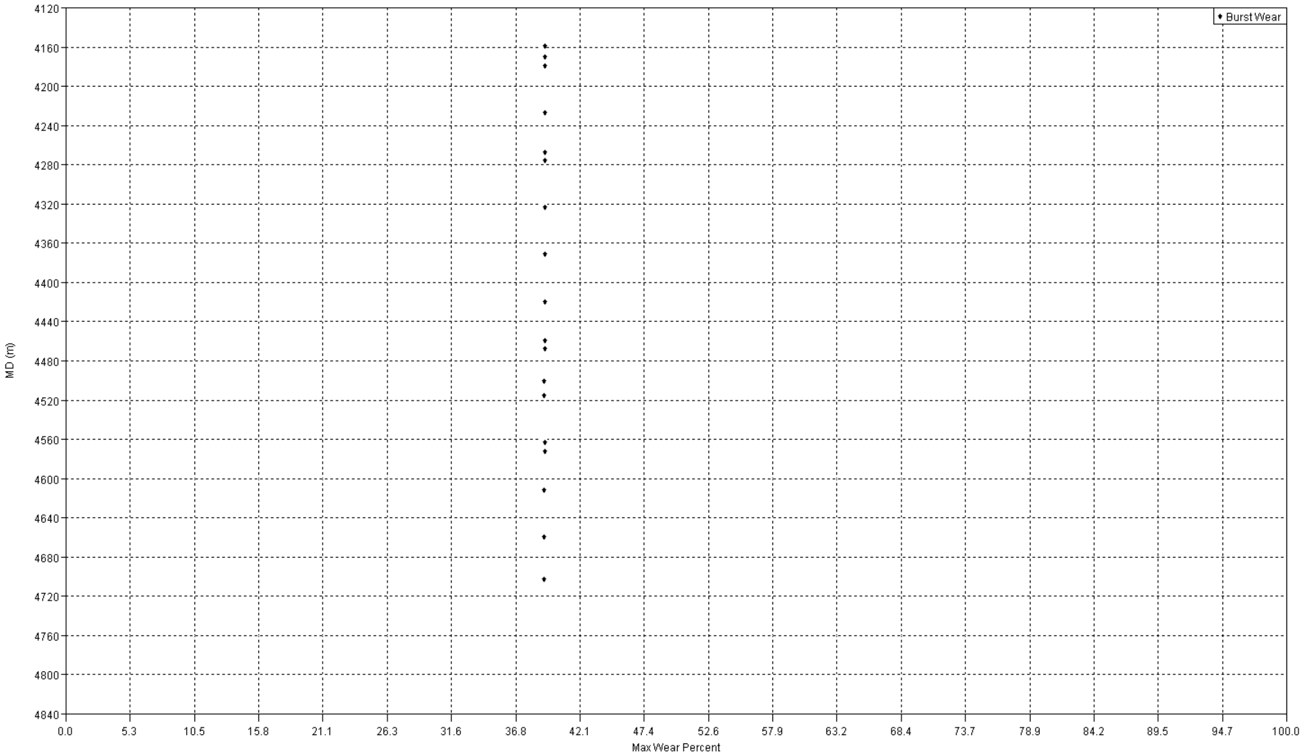


Fig.- 2-4 Casing wear allowance, 5" production liner.

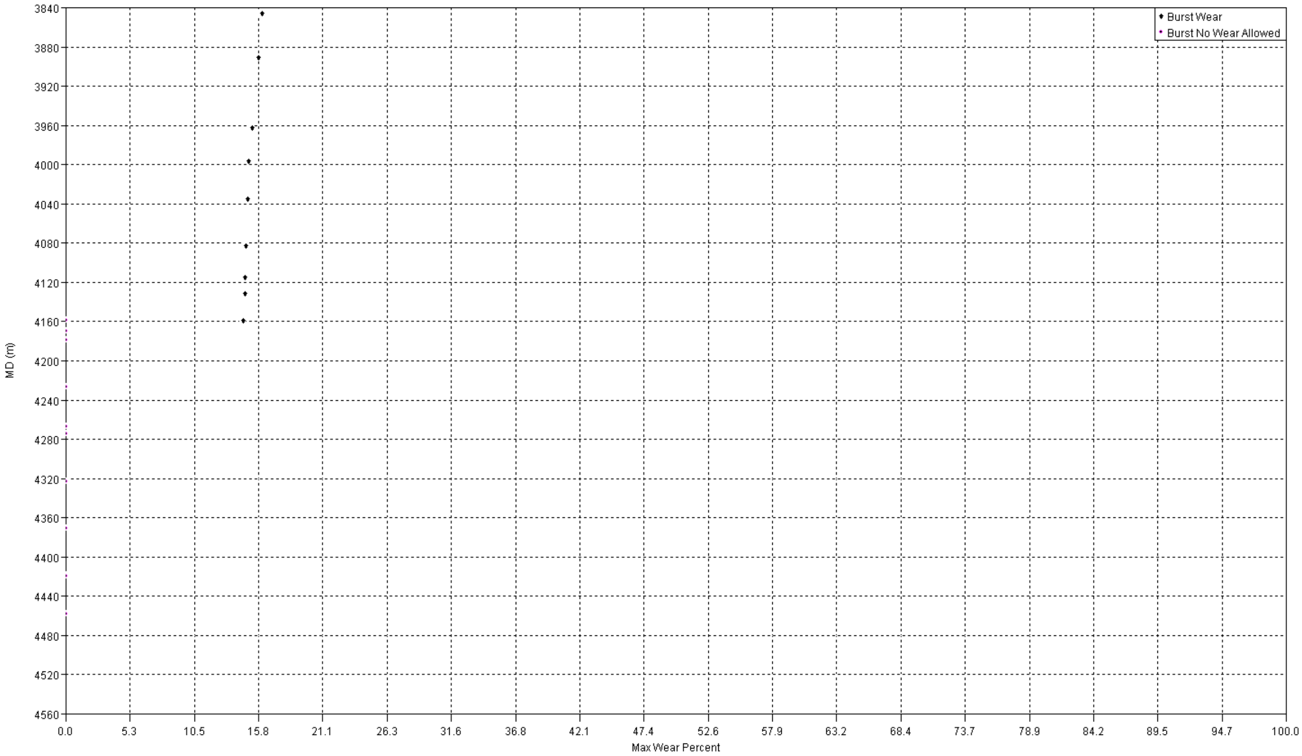


Fig.- 2-5 Casing wear allowance, 7" production liner.

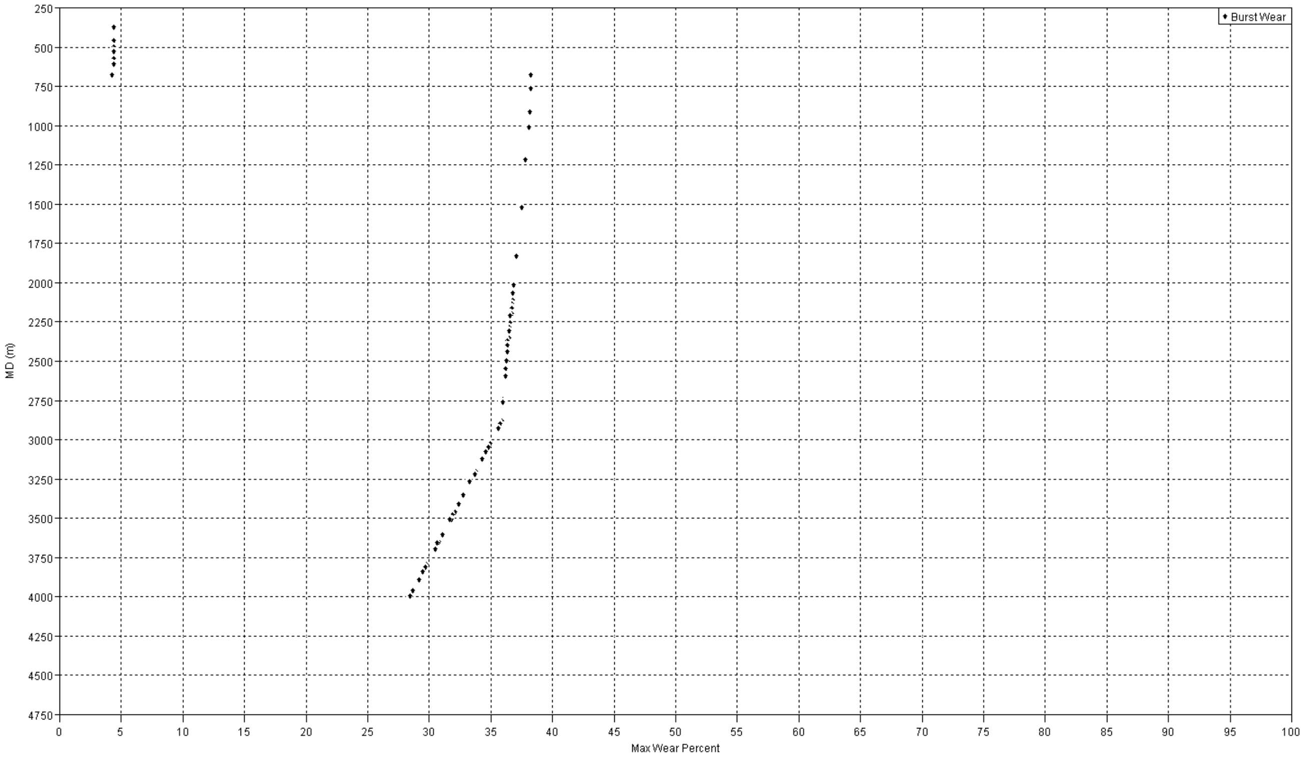


Fig.- 2-6 Carsng wear allowance, 9 5/8" casing.

3 Completion and well design – K-14

3.1 Well Design – Completion of the reservoir section

There are several methods for completing the well. For horizontal wells, there are certain completion properties that are required; possibility for zonal isolation, good solutions for perforating and stimulation, and easy intervention if needed. There are two main ways of completing a horizontal well; open hole completion or cased and cemented completion.

The open hole completion is simply an open borehole in the last section completed bare foot or with tubulars like sandscreens, slotted or pre-holed liner that is segmented for zonal control. The advantages of an open hole completion is maximum exposed flow area and often quicker to install. Slotted liners can only be applied in well consolidated formations, and is usually installed for borehole stability and well intervention access. If a pre-holed liner is installed it is possible to do selective stimulation of the well, as for the Morvin well where swell packers for zonal isolation have been installed. It is also possible to have a degree of sand control, the limitation might be easy blockage of the holes in the liner. The solution is often cheaper than cemented and perforated casing configuration, but if perforation of the well is required for this case the costs due to time consumption can be more significant [Next 2008].

K-14 has been completed with a cemented liner that has to be perforated. This is done because stimulation by hydraulic fracturing is planned for the well. By perforating the well, the inflow will not be affected by any possible damage or fluid infiltration of the near wellbore zone (as seen in Fig.- 3-1).

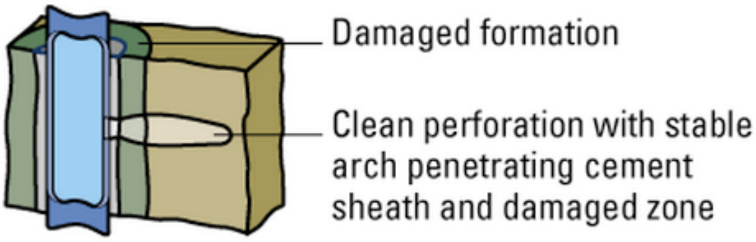

Damaged formation
Clean perforation with stable arch penetrating cement sheath and damaged zone

Fig.- 3-1 Crosssection illustrating perforating through damaged zone [Schlumberger 2012 B].

The main differences between these methods are mainly related to time and costs. Fracturing treatments with the different methods shows similar results for breakdown pressure, fracturing pressure and proppant placements and rates [Schoenfeld et al. 2010]. The simulations in Wellcat™ will not be directly affected by the choice of completion.

3.2 Morvin Open Hole Completion

The casing size selection is the same as for the K14, except for that the setting depths vary because of the difference in pressure gradients in the overburden. The lower part of the pressure gradients id displayed in Fig.- 3-2.

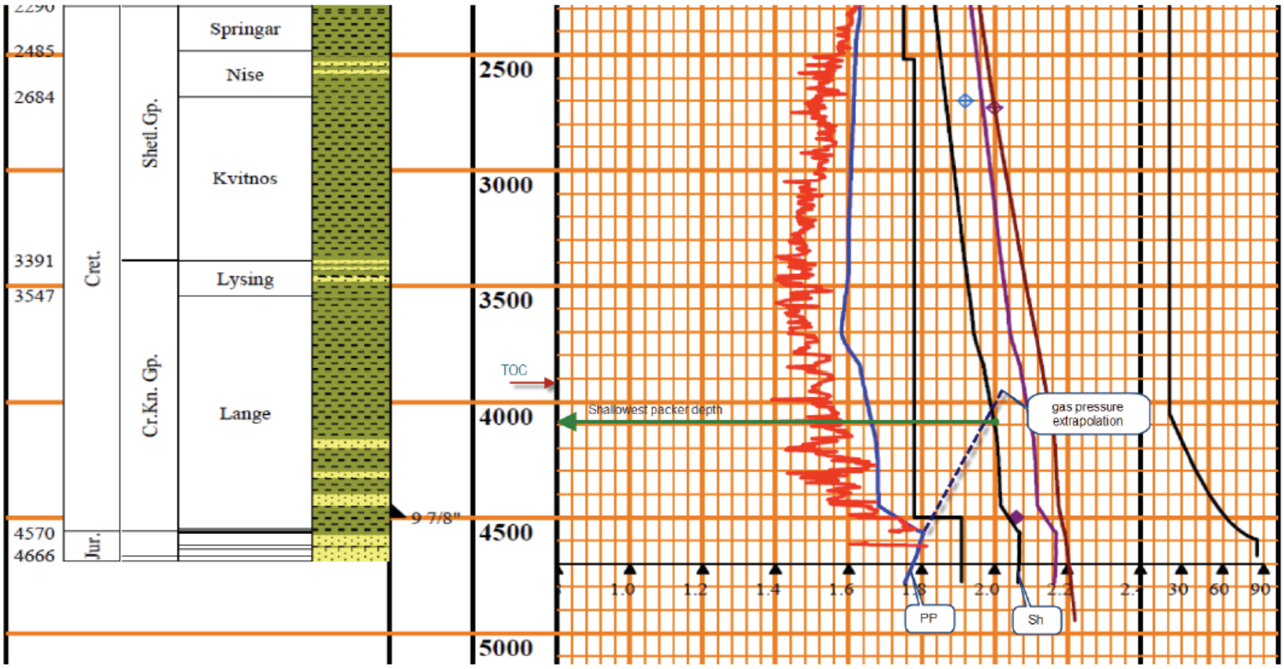


Fig.- 3-2 Pressure gradients for the lower section of the Morvin well.

The Morvin well described in OTC 21476 [Fitnawan et al. 2011] has been completed with 5 $^1/_2$" production tubing and predrilled liner combined with open hole swell packers for zonal isolation control. HPHT tracer subs have been installed for data acquisition. Swell packers and tracer subs may be installed in K-14 well if needed. Cemented liner is planned for K-14 due to the requirement for stimulation by hydraulic fracturing. The complete well design for both K-14 and Morvin are presented in Fig.- 3-3.

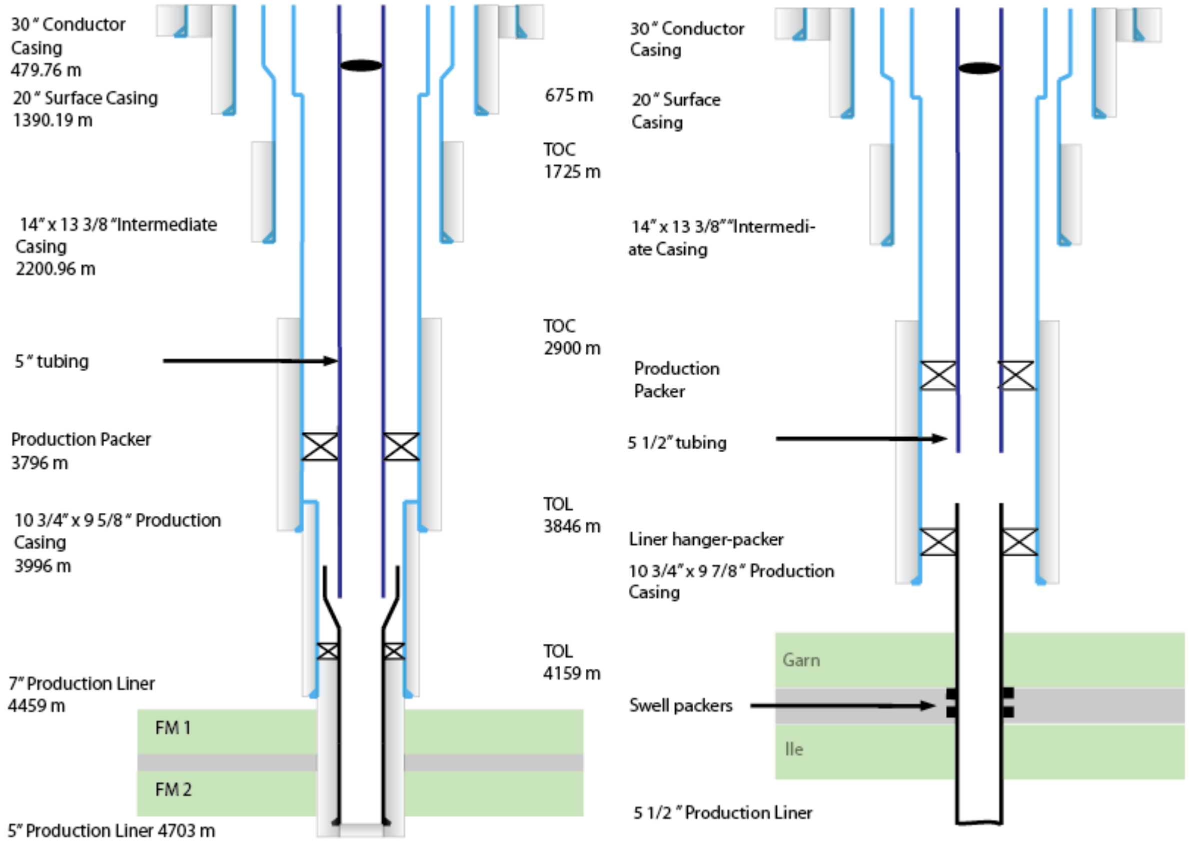

30" Conductor Casing 479.76 m
20" Surface Casing 1390.19 m
14" x 13 3/8 "Intermediate Casing 2200.96 m
5" tubing
Production Packer 3796 m
10 3/4" x 9 5/8" Production Casing 3996 m
7" Production Liner 4459 m
FM 1
FM 2
5" Production Liner 4703 m
675 m
TOC 1725 m
TOC 2900 m
TOL 3846 m
TOL 4159 m
30" Conductor Casing
20" Surface Casing
14" x 13 3/8""Intermedi-ate Casing
Production Packer
5 1/2" tubing
Liner hanger-packer
10 3/4" x 9 7/8" Production Casing
Garn
Swell packers
Ile
5 1/2 " Production Liner

Fig.- 3-3 Well schematic. Left: K-14. Right: Morvin, modified from [Fitnawan et al. 2011].

3.3 Perforating

Because of the high pressure in HPHT wells, the formation rock will have a high strength that can reduce the depth of penetration into the formation. The productivity of the well depends highly on the pressure drop in the zone near the wellbore. This pressure drop is affected by wellbore damage, either by equipment or by infiltrating of well fluid. By perforating past this zone, the inflow parameters can be altered to increase pressure drop and thereby increase the inflow. Perforating parameters like diameter, perforation depth, phasing and perforation conditions in the well (underbalance, fluids, etc.) determine how effective the perforating will be.

For the Morvin completion it has been chosen to avoid cementing and perforation because this will reduce the inflow zone to the well. Well K-14 is planned to be stimulated by hydraulic fracturing and the chosen method is the simplest to ensure successful fracture half-lengths.

In perforated and fractured HPHT wells, special explosives have been used and this will reduce the performance. Perforation guns are commonly run on electricline cables, but with the high pressure in a HPHT well, the seals around the electricline cables are difficult to maintain. Therefore, perforation can be done with coiled tubing or tubing deployed guns. Depending on the temperature of the well, different perforating explosives are used. The most common ones are RDX that are limited to temperatures of 171 °C or less, and HMX that are used in temperatures of up to 204 °C with one hour exposure in the well. If the perforation takes longer than one hour (as for tubing deployed guns), there are explosives that have been tested at 226 °C for 200 hours like the HTX (high temperature explosives). [Baird et al. 1998]

3.4 Tubing selection

The size of the production tubing was thoroughly evaluated for the Morvin field to maximize the production. For well K-14 it has been assumed that the 5″ production tubing will be sufficient to maintain the daily production of 1100 m^3/D. When tubing diameter is reduced, the flow are of the cross section is also reduced. This may lead to a smaller production rate for the 5″ tubing, which again leads to less total production from the field.

3.5 Intervention

Well operations done after the well has started to produce are called well intervention. It is done to alter the state of the well, provide well diagnostics or manage the production. There are several ways to perform well interventions; following is a list of techniques [Wikipedia 2012]:

- **Pressure pumping –** Simply pumping chemicals into the well (no damage to the well).
- **Slickline –** used for fishing, cutting, setting/ pulling plugs
- **Braides line –** used for fishing, logging and perforating
- **Coiled tubing –** chemicals are pumped directly to bottom (tubing wear)
- **Snubbing –** string is forced into the well against wellbore pressure (more rigid than CT)
- **Workover –** replace completions of old wells

4 Well Integrity

Well integrity – “application of technical, operational and organisational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well”. [NORSOK D-010 2004]

4.1 Loads

To plan and evaluate all the possible loads that the well may be exposed to during its lifetime is essential in well integrity. By simulating all possible loads when planning the well, the complete well design will fit the requirements for the expected loads. If an unexpected load is identified, it has to be simulated and then a new pressure test is required.

4.2 Corrosion and equipment wear

The degradation of equipment due to corrosion and wear play a major role in the integrity of the well. Different logging tools are used to determine integrity of the well, by measuring the effect of corrosion and mechanical wear.

As discussed in Chapter 2.5.1 the corrosion rate depend on the fluids produced- and injected into the well as well as the corrosion allowance of the pipe material. It is important for HPHT wells to select a material that has a low corrosion allowance due to the conditions in the well. High temperatures and pressures will affect the chemical reactivity and often induce chemical reactions. Therefore Super Chrome has been used for the 5” liner and the production tubing in K-14.

The parameters affecting the pipe wear in the well are discussed in Chapter 2.5.4. The results of severe casing wear due to drilling and intervention is often that the pipe wall is unevenly worn and that creates a weak spot in the pipe cross section that is more easily fractured.

4.3 Barrier design

4.3.1 Casing program

The selection of setting depths for casings is not only determined by the overburden pressure gradients, but also dependent on the type of formations and their properties. As a common rule a shoe is set before entering the reservoir. The formation above the reservoir has high sealing capacity, this is known by the fact that it has kept the hydrocarbons from escaping the reservoir for a very long time. This means that if there is a leak in the liner going in to the reservoir, the sealing rock will most likely be able to prevent hydrocarbons from reaching the surface.

Another aspect to consider is rapid increase in pore pressure at any point in the well. If this occurs in between two casing shoes, it is important that the top of cement for the lower casing is higher than the point of peak pore pressure. The cement will be able to prevent inflow from this section. If the TOC is not sufficiently high, hydrocarbons may seep into the annulus of the top casing and escape the primary and secondary well barrier.

4.3.2 Cement

As described in the previous section, the height of the cement is an important factor in well integrity. The height has to be planned to withstand the pressure applied at the casing shoe.

Variations in pressure and temperature when cementing may cause small movements in the casing, which leads to the formation of a microannulus. A micro annulus is defined as a small gap between the cement and the tubing, in worst case present around the whole cross section. This results in an escape path for the well fluids. [Schlumberger 2012 C]

Another problem related to temperature and pressure variations when cementing is the possibility for poor bonding in the cement, creating small pathways through the cement.

To verify the quality of the cement job, the well is logged to detect any unconformities and possible leak paths.

4.3.3 Barrier envelope

Several well barriers interlinked together will serve as a barrier envelope for the well. The well barrier elements will wary depending on what type of well operation that is being performed, that being drilling, production (completion design has to be considered), intervention, abandonment, etc. For a production well a common barrier envelope consists of cemented liner, packer, tubing, across the TRSCSSV and back down into the reservoir. At least two barriers are required for wells in operation, while tree envelopes are required for abandonment [NORSOK D-010, 2004]. If one barrier fails, there will be a second to stop the fluid flow to surface. A description of the barrier envelopes planned for K-14 can be found in in the following sections.

4.4 K-14 well integrity

For the K-14 there is two main barriers to keep fluids from flowing uncontrolled to the surface, these are drawn in Fig.- 4-1. The primary barrier is marked in green on the figure. This consists of the production packer, the tubing between packer and TRSCSSV. The secondary barrier, marked red, consists of the cemented casing, 9 $^5/_8$ casing, wellhead with casing hanger, tubing hanger and the subsea production tree.

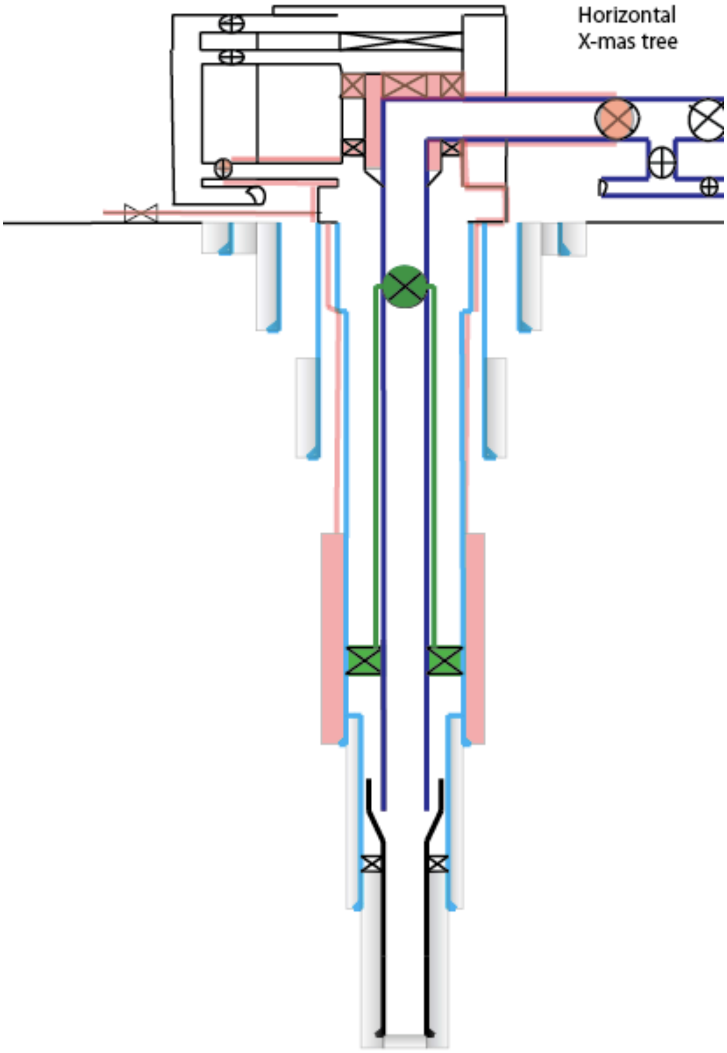


Fig.- 4-1 Primary and secondary well barrier during production, modified from [NORSOK D-010, 2004].

There shall not be any injection into formations that have the possibility to propagate vertical fractures to the surface, the injection has to be lead to only effect the intended layer. Neither shall there be injection into layers that have the possibility to flow, in that case a TRSCSSV has to be installed in the tubing or hydrostatic pressure of the fluid injected has to be greater than the pore pressure.

For injection the well has to be planned based on the following load cases [NORSOK D-010, 2004]:

- Material capability
- Maximum allowable pumping rate
- Maximum expected differential pressure

All of the loads above are taken into consideration in the simulations in Wellcat™.

4.5 Plug and Abandonment

When a well is to be permanently abandoned, the use of two barrier envelopes will not be sufficient. Common primary barrier for a perforated well is cement the liner and install a cement plug across and above the perforations. The secondary barrier may be the cemented casing above the reservoirs, and cement plugs either across the liner top, or outside and inside the tubing (if tubing is present). In addition to the primary and secondary well barrier, there are the following solutions for permanent abandonment:

- Well barrier between two reservoirs, to reduce potential for flow between reservoirs.
- Open hole to surface well barrier, to isolate an open hole from surface when plugging.

The barriers needed for a perforated well are illustrated in Fig.- 4-2. The primary barrier is marked in blue, the secondary in red and the green is the open holed to surface barrier.

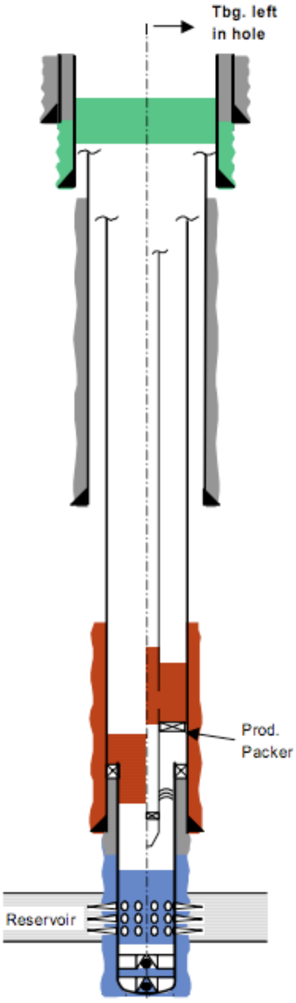


Fig.- 4-2 Well barrier schematic for permanent abandonment - perfortated well [NORSOK D-010, 2004].

The installation of the barriers should be as close to the potential inflow, and cover all possible leak paths. The primary and secondary barrier is to be installed at a depth where the external formation pressure is higher than the internal pressure, this is to support the pipe in case of high internal pressures.

In case of sidetracking the well, the original wellbore has to be permanently abandoned before a sidetrack/ slot recovery is initiated. For permanent/ long term abandonment the equipment has to be verified to withstand any chemical degradation that will happen over time.

Steel tubulars no is not accepted as a permanent well barrier element unless it is cemented, and elastomers used as sealing components is neither accepted for permanent well barrier. [NORSOK D-010, 2004]

4.6 Other

Material selection of pipes is essential for well integrity. Selecting the right material and grade is discussed in Chapter 2.5.

For HPHT wells the production packer needs to be sealed off by a metal-to-metal connection due to the extreme temperature and pressure in the well. The well conditions have a severe effect on elastomers, making them brittle and lose the sealing capacity, and therefore can not be used in well barrier, only used as a back up for the metal seal.

Other aspects that have to be considered related to well integrity are sand control, hydrates, scale, etc. These are described in further detail in Appendix A.8.

5 K-14 Stress Analysis

Stress analysis for K-14 comprises investigations of loads on tubing, packer and exposed casing. For the tubing design to be complete, all the loads that the well can be exposed to in its lifetime have to be evaluated. The loads have been selected on the base of the order the most likely will appear. Table 5-1 below provides an overview of the loads that are taken into consideration when designing the well. The first 9 loads described (from 1 to 9) are production loads, while the remaining loads are described as installation/intervention loads.

Table 5-1 Simulated load cases.

	Production Loads		Installation/Intervention Loads
1	Clean up	**A**	Initial conditions
2	Early life production	**B**	Pressure test
3	Shut in short	**C**	Tubing leak
4	Shut in long	**D**	Tubing evacuation
5	Bullhead	**E**	Mini-fracturing
6	Kill	**F**	Screen out
7	Breakdown		
8	Fracturing		
9	Annulus active		

The pressure test load will cover and be a greater load than all other loads listed. This is how the wells are qualified for service. All the specific input values that have been used for the loads in Wellcat™ are shown in Appendix A.6. Wellcat™ functions and how K-14 was modelled and run is demonstrated in Appendix A.5.

5.1 Load principals

The pressure seen by the tubing and the exposed casings are shown in Fig.- 5-1 below. The fluid present in the tubing and the area below the packer will vary depending on what load case is simulated. The pressures are identical on both sides of the figure, but to simplify the figure the forces have been drawn only on one side. There are four different pressure scenarios that have to be taken into consideration:

1. The internal pressure acting on the cemented 9 $^5/_8$″ casing supported by the formation, ΔP_1.
2. The internal pressure above the top of the 5″ liner acting on the cemented 7″ liner supported by the casing, ΔP_2.
3. The differential pressure between the pressure from the production stream and the hydrostatic pressure of packer fluid acting on the production packer, ΔP_3.
4. The differential pressure between the hydrostatic column of produced fluid and the cemented liner hanger, ΔP_4.

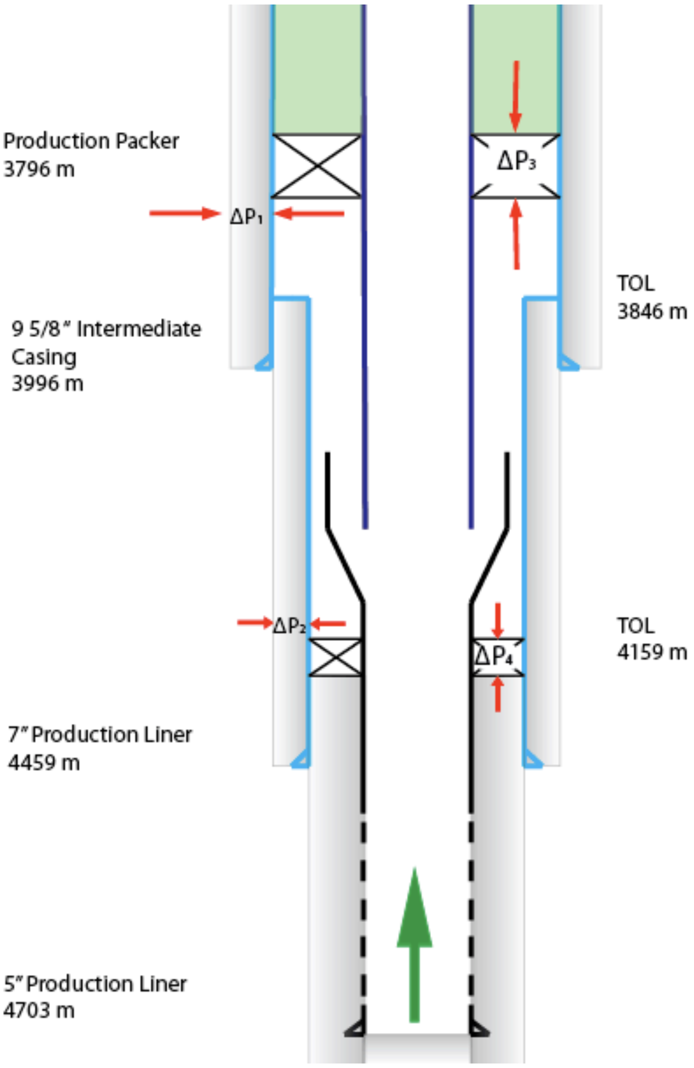

Production Packer
3796 m
ΔP₁
ΔP₃
TOL
3846 m
9 5/8" Intermediate
Casing
3996 m
ΔP₂
ΔP₄
TOL
4159 m
7" Production Liner
4459 m
5" Production Liner
4703 m

Fig.- 5-1 Pressure acting on casings, tubing and packer.

6 Results

The results of the load simulations in Wellcat™ are presented in this chapter. For the completion design to be complete all the equipment that experience a load has to be evaluated. When analysing the effect the loads has on the well, the well has been split into three categories: tubing, liners, casing below packer and the packer. All the loads are described in detail in Appendix A.6, where the most critical load in all cases are the pressure test. The pressure test was first set to 800 bar, but as the exposed casings and liner were investigates, it showed that the pressure were too high and bursting would occur. The pressure was decreased to 700 bar and grade and material for pipes and connections were increased to be able to withstand the pressure test. The final test results are presented below.

6.1 Tubing results

6.1.1 Design limit plot

The tubing will be able to withstand all the loads it may be exposed to during its lifetime. This can be seen from the design limit plot (Fig.- 6-1) and how all the loads are placed inside the limits of the Von Mises plot, which shows the pipe and connections limits. As seen in the top right quadrant, the pressure test is the highest burst load. Turing loads like Annulus test, Tubing leak and Tubing evacuation the tubing experience high collapse force due to the high external pressure.

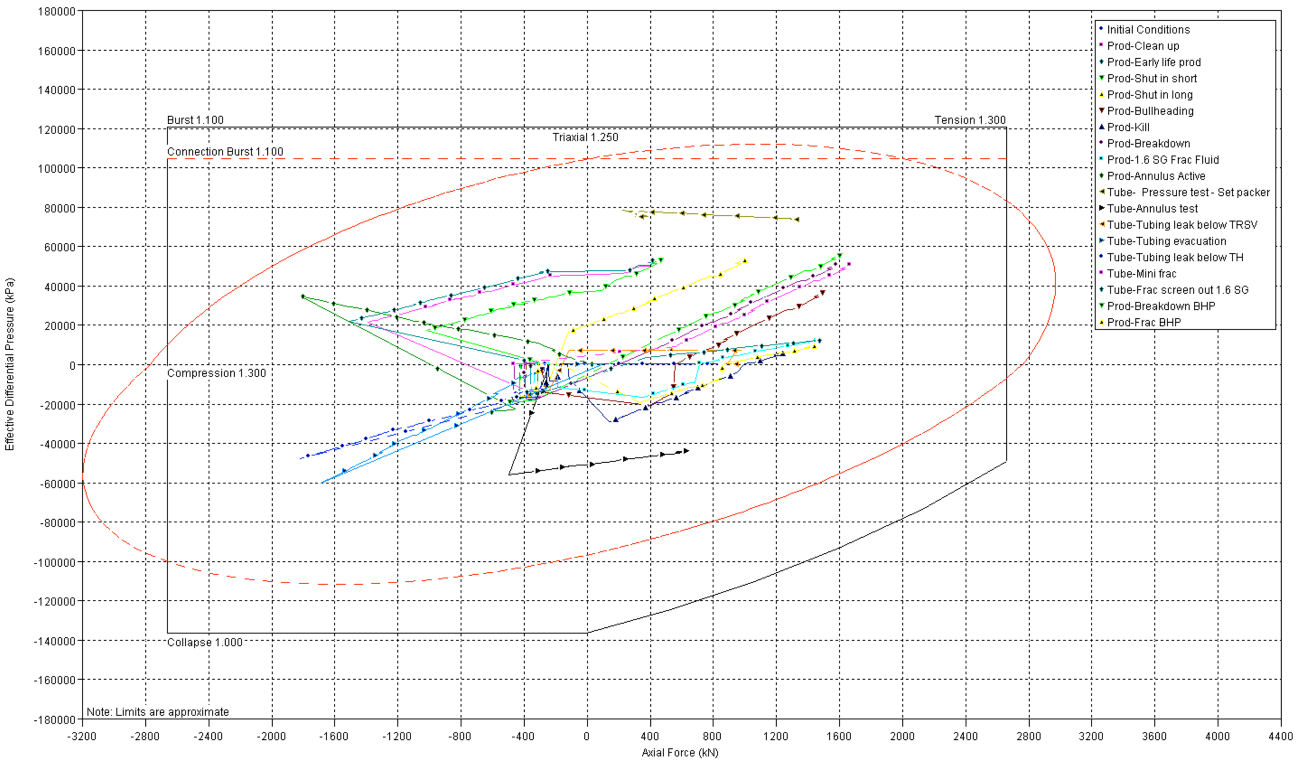


Fig.- 6-1 Design limit plot, tubing.

6.1.2 Differential Pressure

The differential pressures for the load scenarios are displayed in Fig.- 6-2. Some of the loads initiate a negative differential pressure meaning that the tubing will experience collapse forces, also seen from the DLP. As seen from the plot, the highest differential pressure is created by the pressure test. This is the most extreme load the well will ever be exposed to. By performing a pressure test that is inside the limit of the design limit plot, the tubing is qualified to take loads that have a lower differential pressure than the pressure test. If future interventions of the well require a higher differential pressure that the existing pressure test, a new simulation has to be done and a new pressure test has to be carried out.

The tubing can I theory see a higher load than the pressure test, but in this case it should be supported with pressure in the annulus so the differential pressure – or absolute load – is not exceeding the set design pressure of the well (the pressure test). An example of this could be during stimulation by hydraulic fracturing: The tubing is pressurised using a higher internal pressure as long as the annulus pressure reduces the effective load to less than the pressure test.

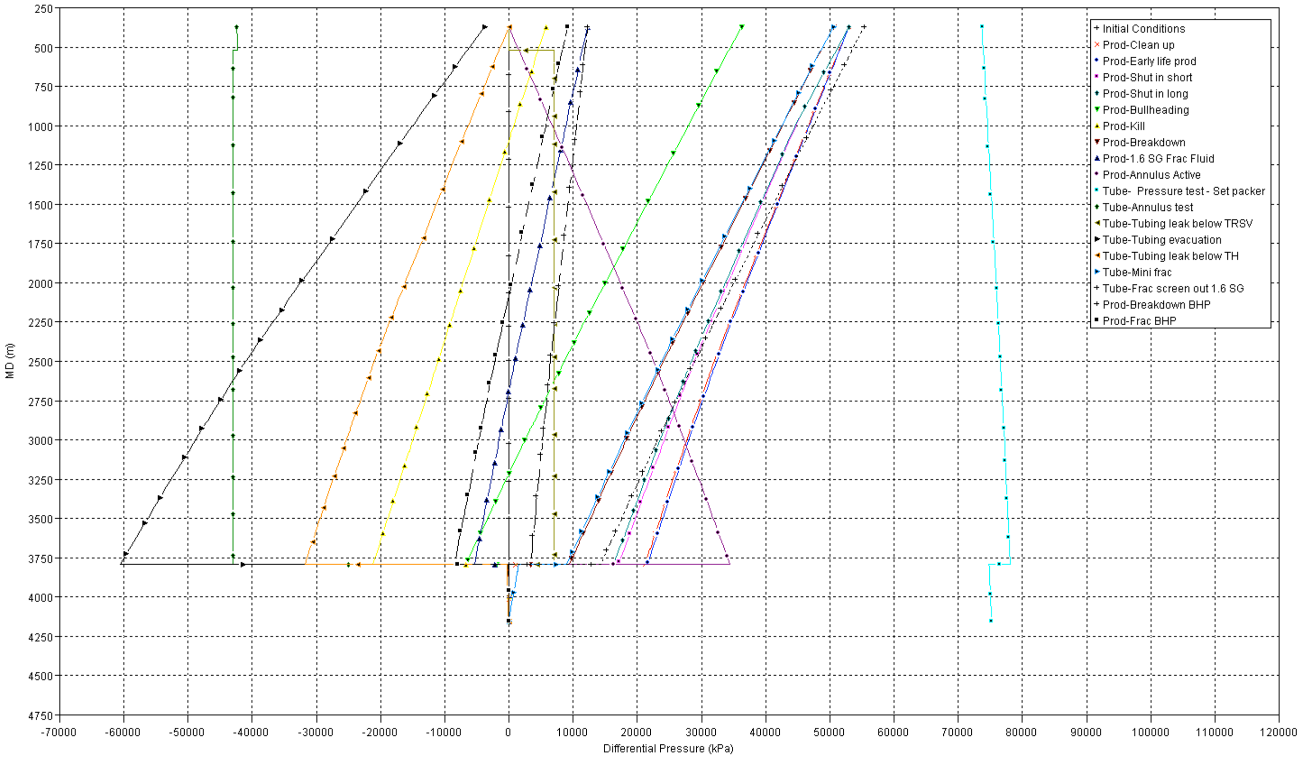


Fig.- 6-2 Differential pressure, tubing.

6.1.3 Internal pressure

As seen from Fig.- 6-3, all the loads applied to the well have an increasing pressure towards depth, and the pressure test has the highest internal pressure.

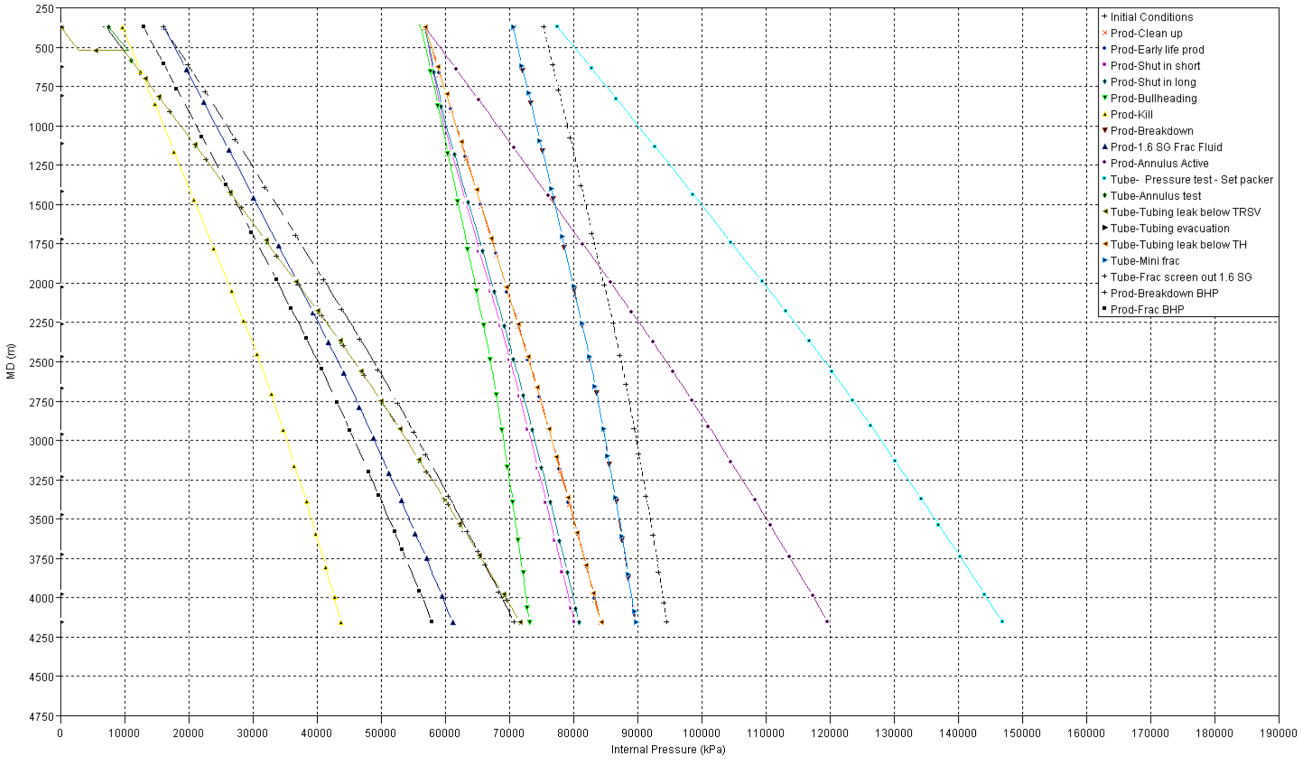


Fig.- 6-3 Internal pressure, tubing.

6.2 Casing results

The casing and liners below the production packer are exposed to the same loads as the tubing, so to do a full completion design these casings/liners has to be investigated. All the casings and liners that are exposed are cemented in place for the interval of interest. This will give an extra pressure support, but no design philosophy accepts using cement as support for tubulars. Therefore, external pressure profile for the casing is set to be the pressure of the fluid gradient with pore pressure, while for the liners the pressure is determined by the pressure above/below the prior shoe (this is Wellcat™ terminology and means the same, only that one is adapted for liners and the other for casing). Initially, when the pressure test was set to 800 bar, not all casings fitted into the design limit plot, alterations related to the steel selection were performed in order to meet the requirements.

6.2.1 Design Limit Plot

All the loads for the casing and liners are located in the burst section of the design limit plot (except for initial load that is neutral). This is because they only experience internal pressure, on the external side cement and formation pore pressure support the tubulars. The highest burst load is the pressure test.

5"- Production Liner

The whole length of the 5" production liner will be exposed to the same service loads as for the production tubing, and pressure tested to verify that all the loads can be supported by the liner. As seen from the design limit plot (Fig.- 6-4) all the loads that it is exposed to are within the limits of the Von Mises ellipse, and the connection limits; the liner will stay intact. The material and steel grade that have been used for this section is Super Crome-110, which is common to use in HPHT wells, as described in Chapter 2.5.

7" – Production Liner

For the 7" liner it is only the top 312 m that is exposed, the cemented 5" liner covers the lower part, to simplify the plot it is only the exposed part of the liner that is shown. The loads are inside the limits for the pipe and connections; the liner will stay intact (Fig.- 6-5).

9 5/8" – Production Casing

The part of the 9 5/8" production casing that sees the loads is located between the production packer and top of the 7" liner, and this part is displayed in the design limit plot (Fig.- 6-6).

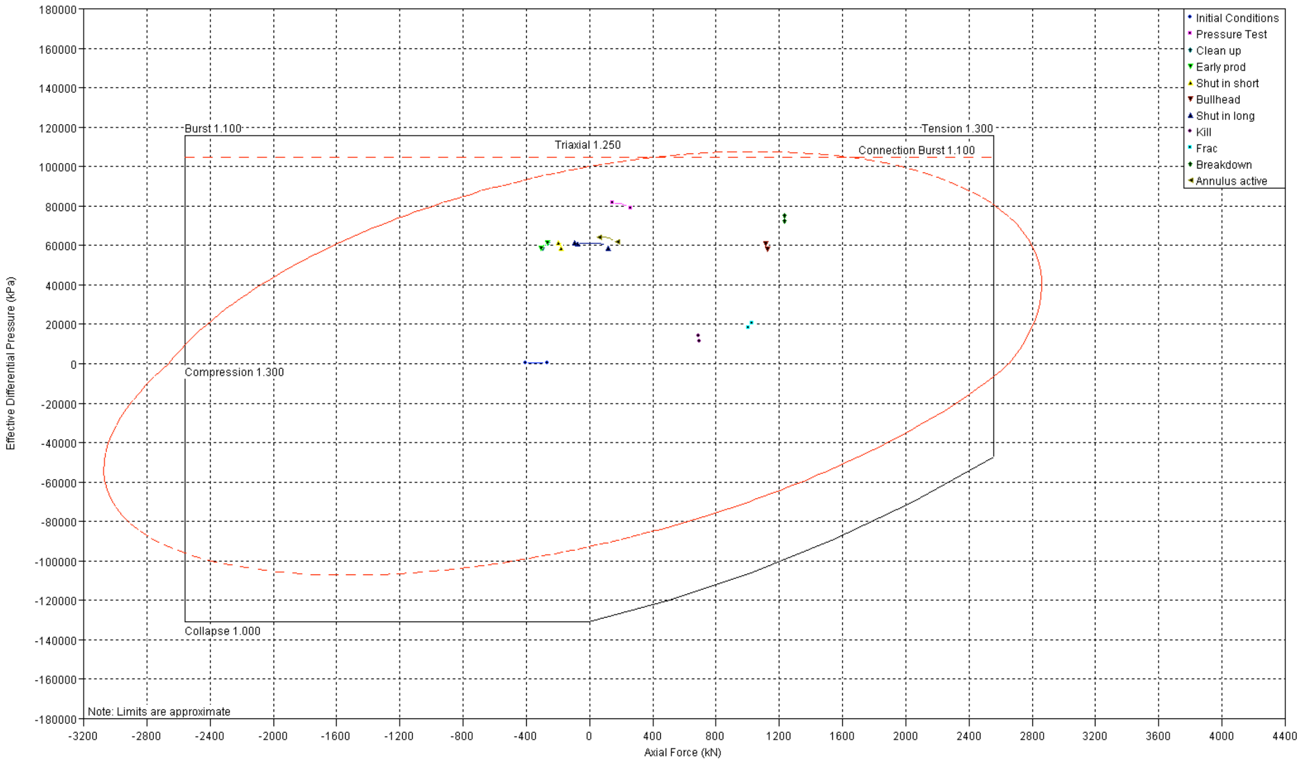


Fig.- 6-4 Design limit plot, 5" Production Liner.

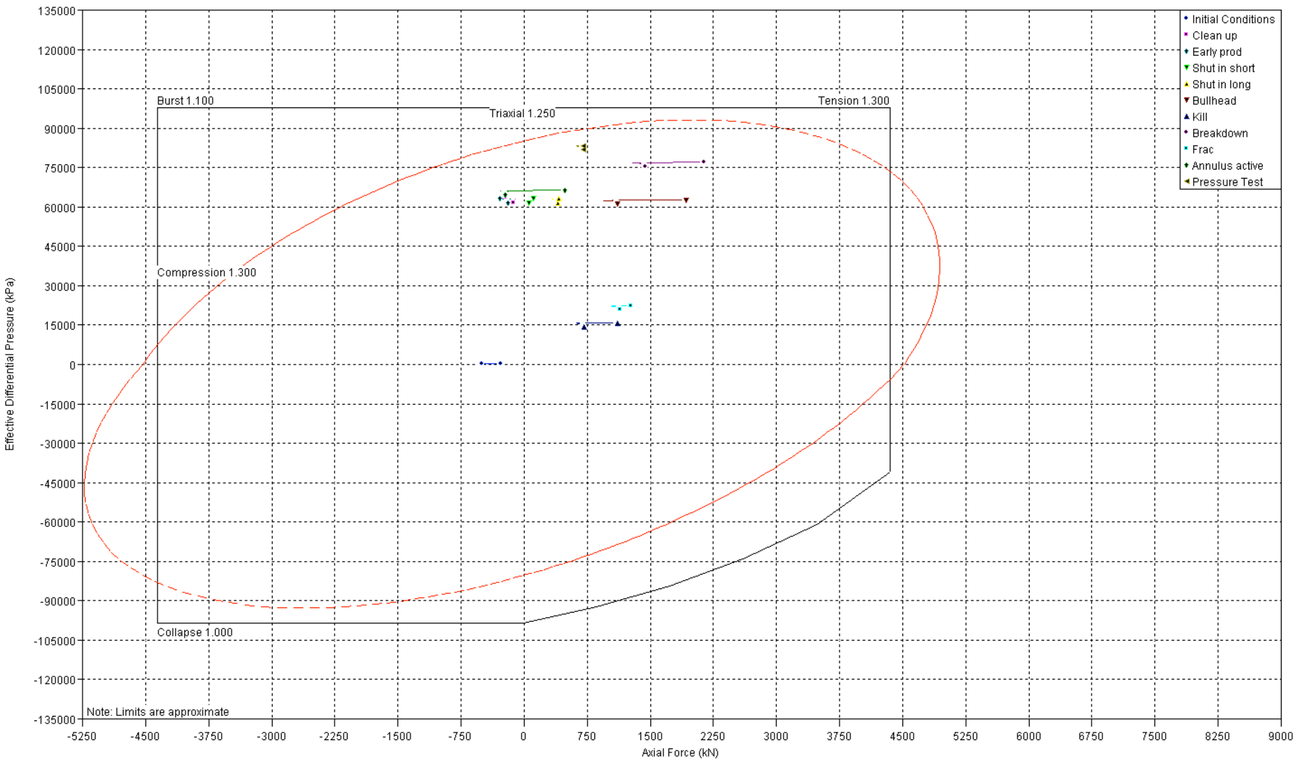


Fig.- 6-5 design limit plot, 7" liner.

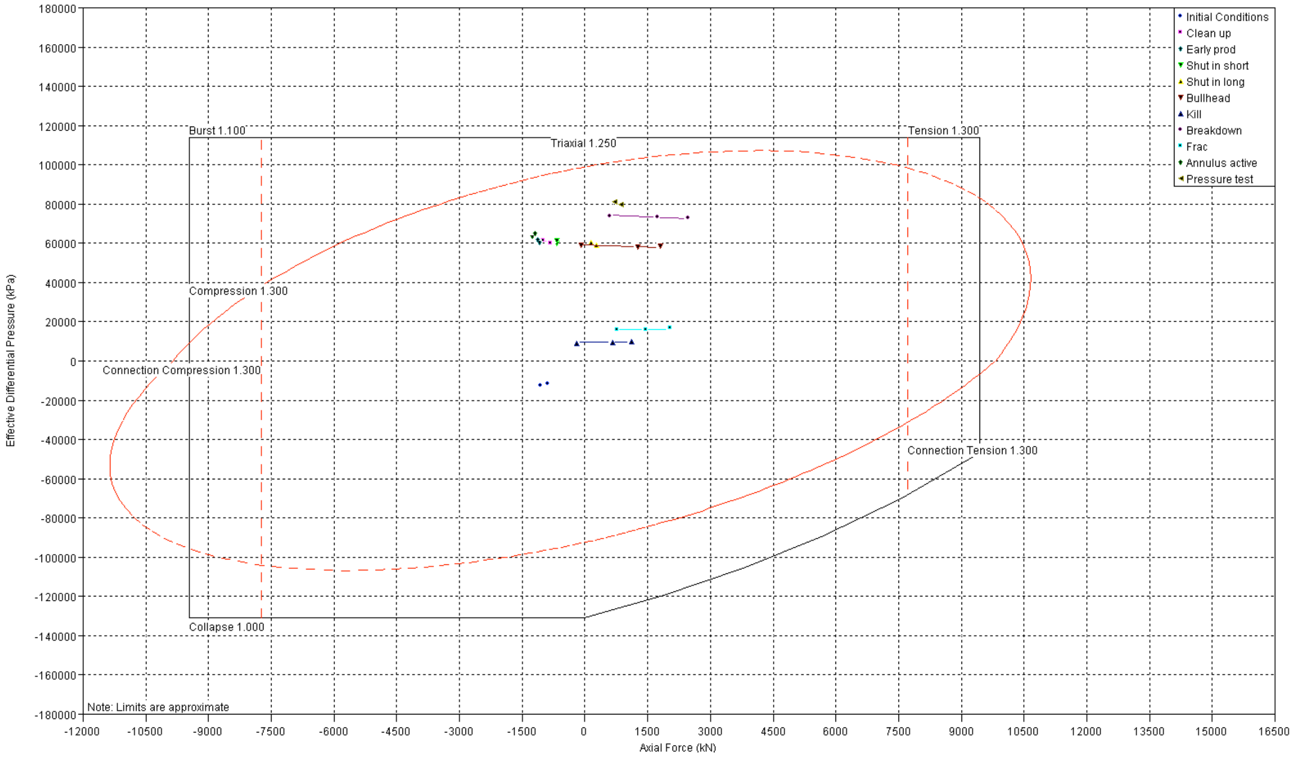


Fig.- 6-6 Design limit plot, 9 5/8" casing.

6.2.2 Differential pressure

The pressure test has to be the greatest load that the casings will se, as for the tubing. When the tubing is pressure tested, the casings have to be able to take the load of this. It is therefore important to compare design limit plots to the differential pressure plot to investigate that the load is within the limits of Von Mises, and that the pressure test is the highest differential pressure seen by casings. This has to be done for every casing/liner that see the load.

5″ Production Liner

The differential pressure of the pressure test is marked orange in Fig.- 6-7. The second highest differential pressure is set by the breakdown of the formation. That is due to the high pressure that needs to be overcome in order to induce a fracture. Hydraulic fracturing and Kill operations normally do not require the highest pump pressure to be performed, therefore the differential pressure is low.

7″ – Production Liner

The differential pressure that acts on the exposed section of the 7″ production liner is shown in Fig.- 6-8. The pressure test is marked in blue, and is the highest differential pressure.

9 5/8″ – Production Casing

The differential pressure of pressure test for the 9 5/8″ tubing is marked in blue in Fig.- 6-9, again showing that this is the greatest differential pressure of all the loads. Where the differential pressure start to increase at 3000 m indicates where the top of cement is (2900 m). From this point the external pressure decrease due to 7″ liner being placed inside the 5/8″ casing, and an increased in the thickness of cement.

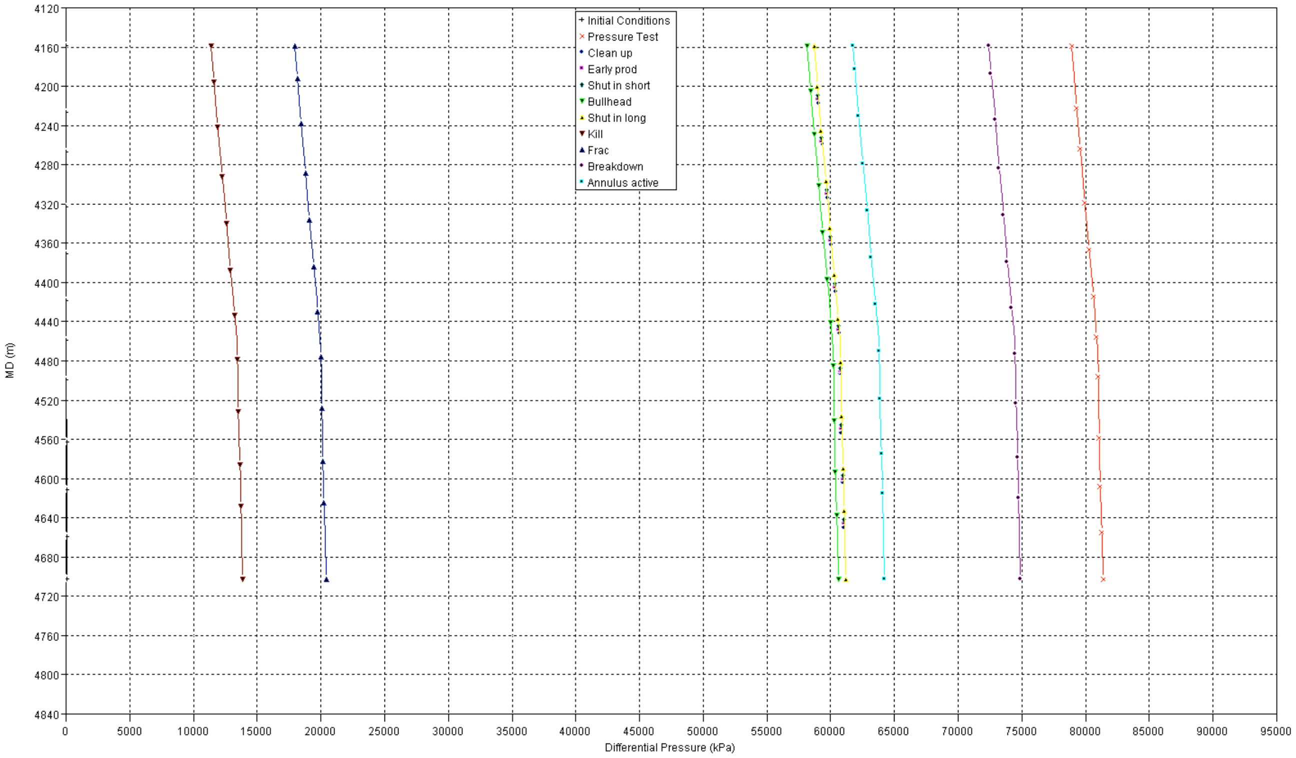


Fig.- 6-7 Differential pressure, 5" production liner.

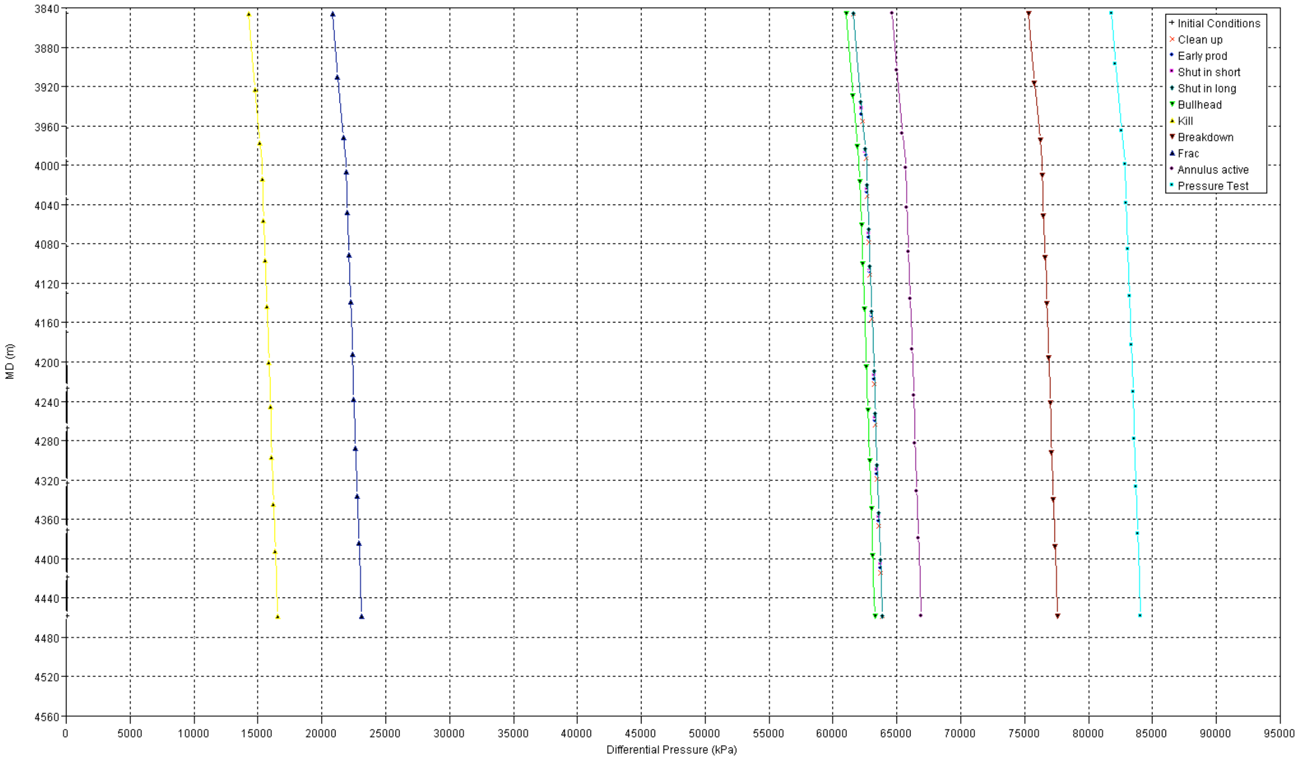


Fig.- 6-8 Differential pressure, 7" production liner.

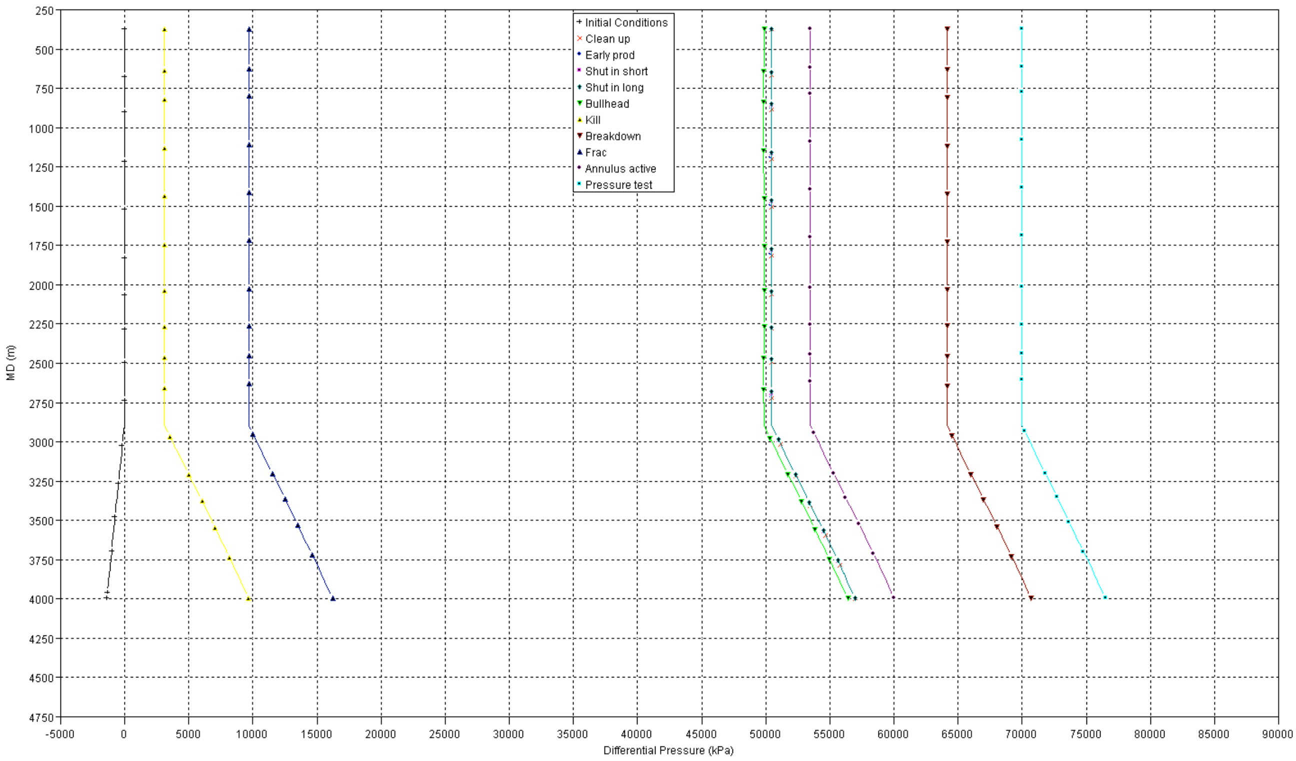


Fig.- 6-9 Differential pressure, 9 5/8" casing.

6.3 Packer results

The packer selected for this completion is SB-3H Production Packer (Fig.- 6-10) developed by Baker Oil Tools based on the field proven SB-3 Retainer Production Packer [Baker Oil Tools 2008]. This packer is not dimensioned for K-14, but it has been used to illustrate how to plot the tubing-to- packer forces. The packer was set hydraulically at 3796.28 m MD at an initial set pressure of 345 bar and a plug depth of 3840.48 m MD. The axial load change after packer set is 44.48 kN, and seal bore is present.

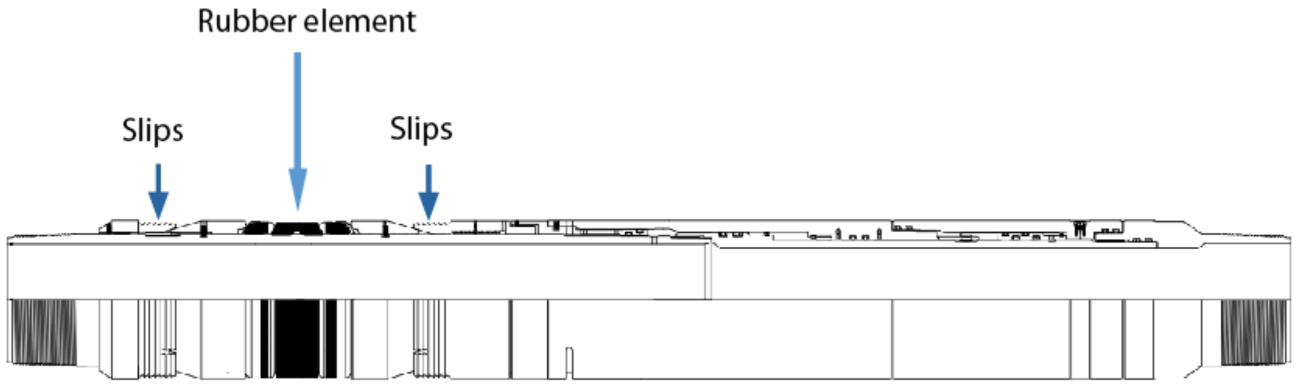
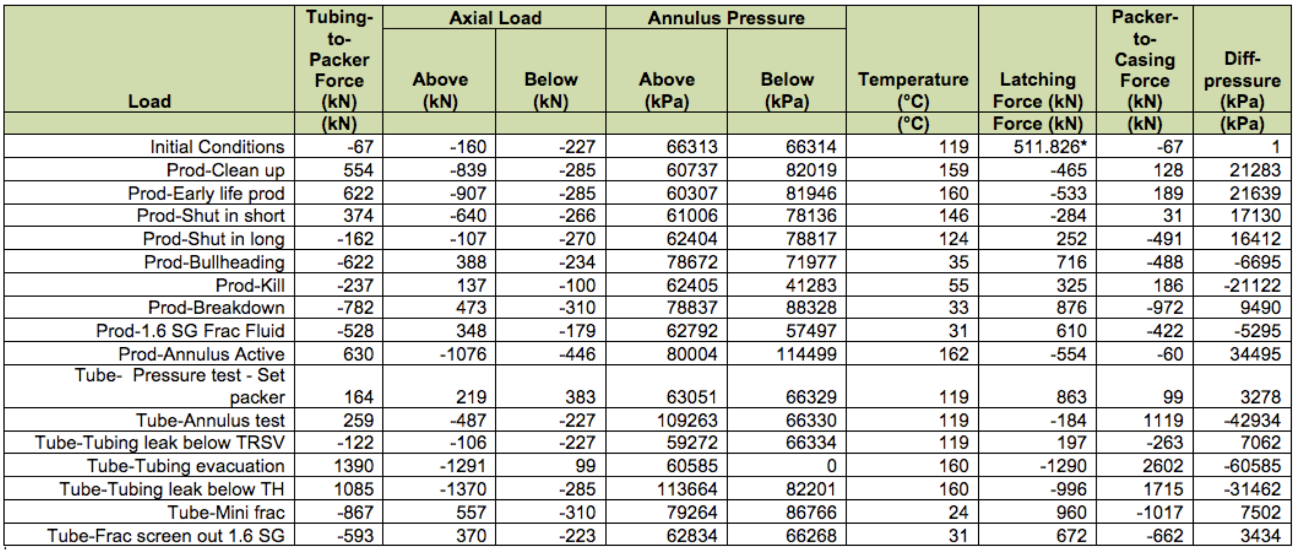


Fig.- 6-10 Production packer, drawing no. A28-993-00 [Baker Oil Tools 2008].

6.3.1 Tubing to packer forces

The force that has been investigated is the one between the tubing and the production packer. The result of the load calculations is shown in Table 6-1**,** where negative forces are in the upward direction. When selecting the production packer the tubing-to-packer force (axial load, below-above) and the differential pressure (annulus pressure, below-above) have to be taken into consideration. The most extreme loads are investigates, and has to fit inside the production packer envelope. The highest tubing to packer force is from the Tubing Evacuation, 1390 kN, and the differential pressure is -60 585 kPa. Negative forces are in the upward direction, which means when the differential pressure is negative that the pressure above the packer is greater than below. The schematic of the forces applied to the packer is shown in Fig.- 6-12.

Table 6-1 Tubing-to-packer forces.



Load	Tubing-to-Packer Force (kN)	Axial Load		Annulus Pressure		Temperature (°C)	Latching Force (kN)	Packer-to-Casing Force (kN)	Diff-pressure (kPa)
		Above (kN)	Below (kN)	Above (kPa)	Below (kPa)				
	(kN)					(°C)	Force (kN)	(kN)	(kPa)
Initial Conditions	-67	-160	-227	66313	66314	119	511.826*	-67	1
Prod-Clean up	554	-839	-285	60737	82019	159	-465	128	21283
Prod-Early life prod	622	-907	-285	60307	81946	160	-533	189	21639
Prod-Shut in short	374	-640	-266	61006	78136	146	-284	31	17130
Prod-Shut in long	-162	-107	-270	62404	78817	124	252	-491	16412
Prod-Bullheading	-622	388	-234	78672	71977	35	716	-488	-6695
Prod-Kill	-237	137	-100	62405	41283	55	325	186	-21122
Prod-Breakdown	-782	473	-310	78837	88328	33	876	-972	9490
Prod-1.6 SG Frac Fluid	-528	348	-179	62792	57497	31	610	-422	-5295
Prod-Annulus Active	630	-1076	-446	80004	114499	162	-554	-60	34495
Tube- Pressure test - Set packer	164	219	383	63051	66329	119	863	99	3278
Tube-Annulus test	259	-487	-227	109263	66330	119	-184	1119	-42934
Tube-Tubing leak below TRSV	-122	-106	-227	59272	66334	119	197	-263	7062
Tube-Tubing evacuation	1390	-1291	99	60585	0	160	-1290	2602	-60585
Tube-Tubing leak below TH	1085	-1370	-285	113664	82201	160	-996	1715	-31462
Tube-Mini frac	-867	557	-310	79264	86766	24	960	-1017	7502
Tube-Frac screen out 1.6 SG	-593	370	-223	62834	66268	31	672	-662	3434

As an illustration, the loads selected for plotting in Fig.- 6-11 are: Tubing evacuation, Tubing leak, Bullheading and Annulus active. They all fit into the envelope of the selected packer. When plotting the values from Table 6-1 the tubing to packer force has to change to the opposite notion, while the differential pressure is plotted as it is.

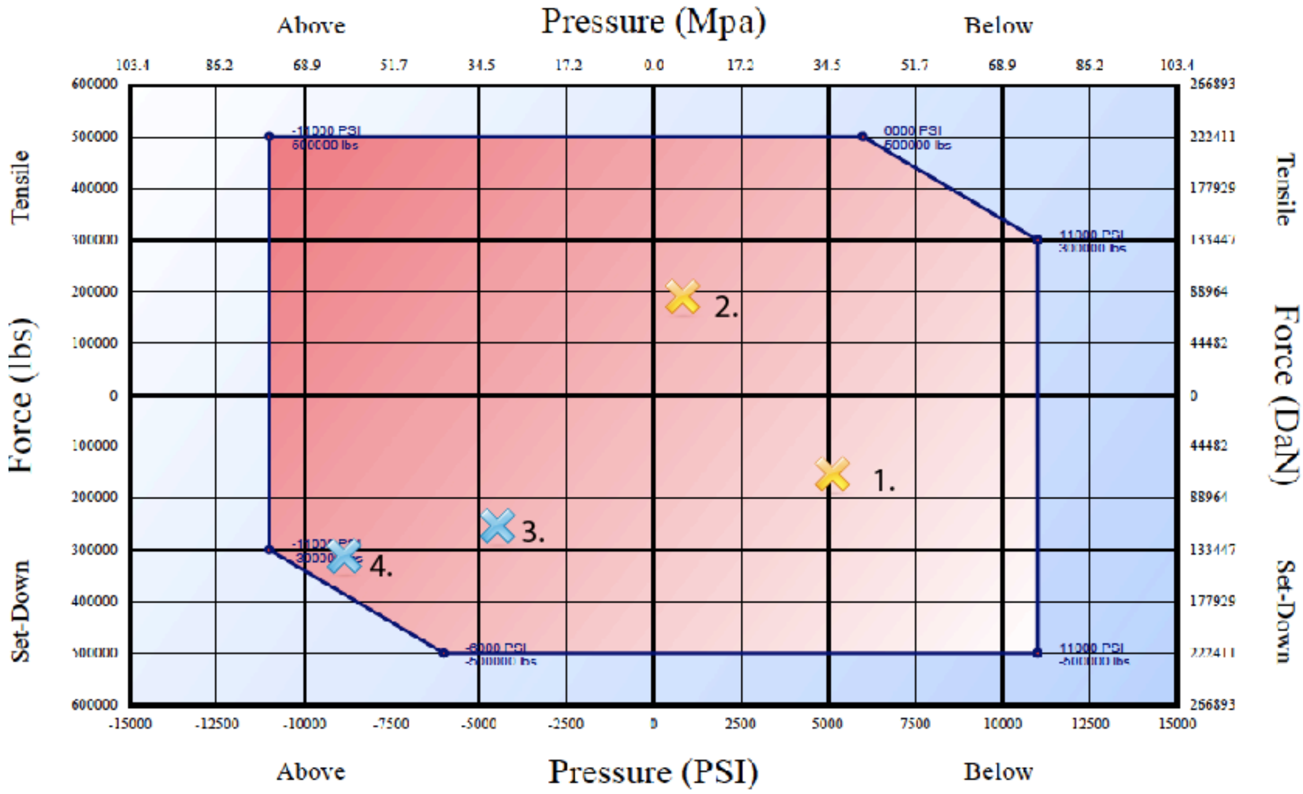


Fig.- 6-11 Packer envelope; 1-Annulus active, 2-Breakdown, 3-Tubing leak below tubing hanger, 4-Tubing evacuation.

As seen from the plot, tubing evacuation is the most severe load on the packer. All other loads simulated are within the limits of the production packer. The packer has been placed in the 9 5/8" casing. If tubing-to-packer forces and differential pressures for K-14 were too high for the packer, the solution could be installed the packer in the 7" liner. This would automatically give a larger packer envelope due to the reduction in the area exposed to pressure. This has not been done for K-14 due to later perforation of the 7" liner.

Packer schematic; Tubing Evacuation

The forces from Table 6-1 drawn on the packer schematic is shown by Fig.- 6-12. A more detailed description of the tubing to packer force can be found in Appendix A.7. For the load case of tubing evacuation the tubing-to-packer force is in the downward direction, meaning that the pressure above the packer is higher than below. This is because the tubing, which supplies pressure below packer, is evacuated and the pressure is depleted.

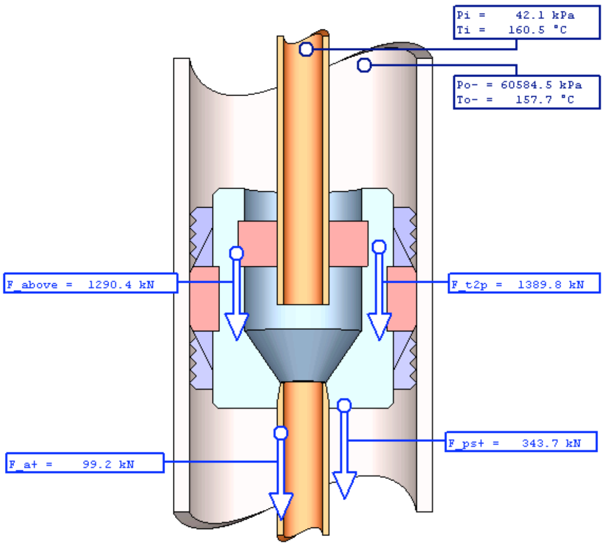


Fig.- 6-12 Tubing-to-packer force, Tubing evacuation.

6.4 Hydraulic fracturing

The hydraulic fracturing of the well can be divided into four different operations; Breakdown, Mini-Fracturing, Fracturing and Screen-out.

Steps in hydraulic fracturing [V Completion Team 2012]:

1) Lift packer fluid out an create an underbalance in the well
2) Perforate and flow back
3) Break down formation using seawater
4) Perform mini-fracturing
5) Pump 1.6 SG fracturing fluid
6) Screen out

The steps from 3 to 6 are simulated in Wellcat™. The process of hydraulic fracturing is dynamic, which means that for each step of injection, the pressure/loads will change throughout the operation (described in more detail in Appendix A.6.7).

The break down magnitude is affected by parameters like fluid viscosity, pump rate, porosity of rock, etc. For the hydraulic fracturing the densities of the fluid injected has been compared to required wellhead pressure (WHP) and the matching bottom hole pressure (BHP). The evaluation that has been done for K-14 is to see the effect different fluid densities and pressures will have on tubing, casing and packer.

Table 6-2 Pressures for different fracture fluid densities.

	Low Density (1.03 SG)	High density (1.6 SG)
WHP [bar]	705.8	161
BHP [bar]	1010	707

As seen in Fig.- 6-13 the result from the fracturing and bullheading give corresponding results to whether it is wellhead pressure or bottom hole pressure that is used.

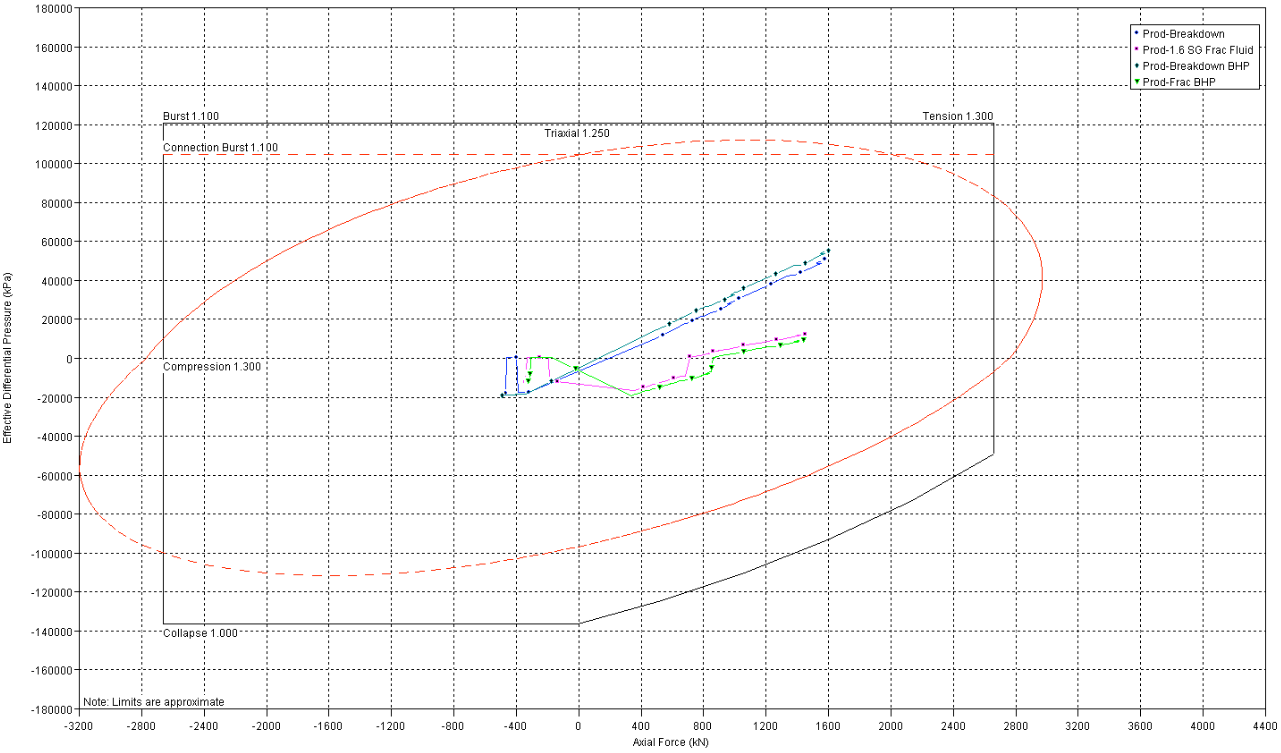


Fig.- 6-13 Bullheading and fracturing, WHP and BHP.

6.4.1 Parameters

Pump Pressure

The density of the fluid present in the pipe determines the pump pressure required at wellhead. This means that if the density of the fracturing fluid is to be increased, the wellhead pressure has to be reduced to accommodate for the extra hydrostatic pressure.

If wellhead pressure is to be increased on the 1.6 SG fracturing fluid, it had to be increased to 1100 bar before the connections would burst and at 1150 the tubing would fracture. It would experience a high burst-tension force, and the differential pressure would be much greater than of the initial pressure test. When increasing the wellhead pressure to such an extent, the pressure test is no longer valid. The pressure test cannot be increased because then the exposed casings and liners will burst.

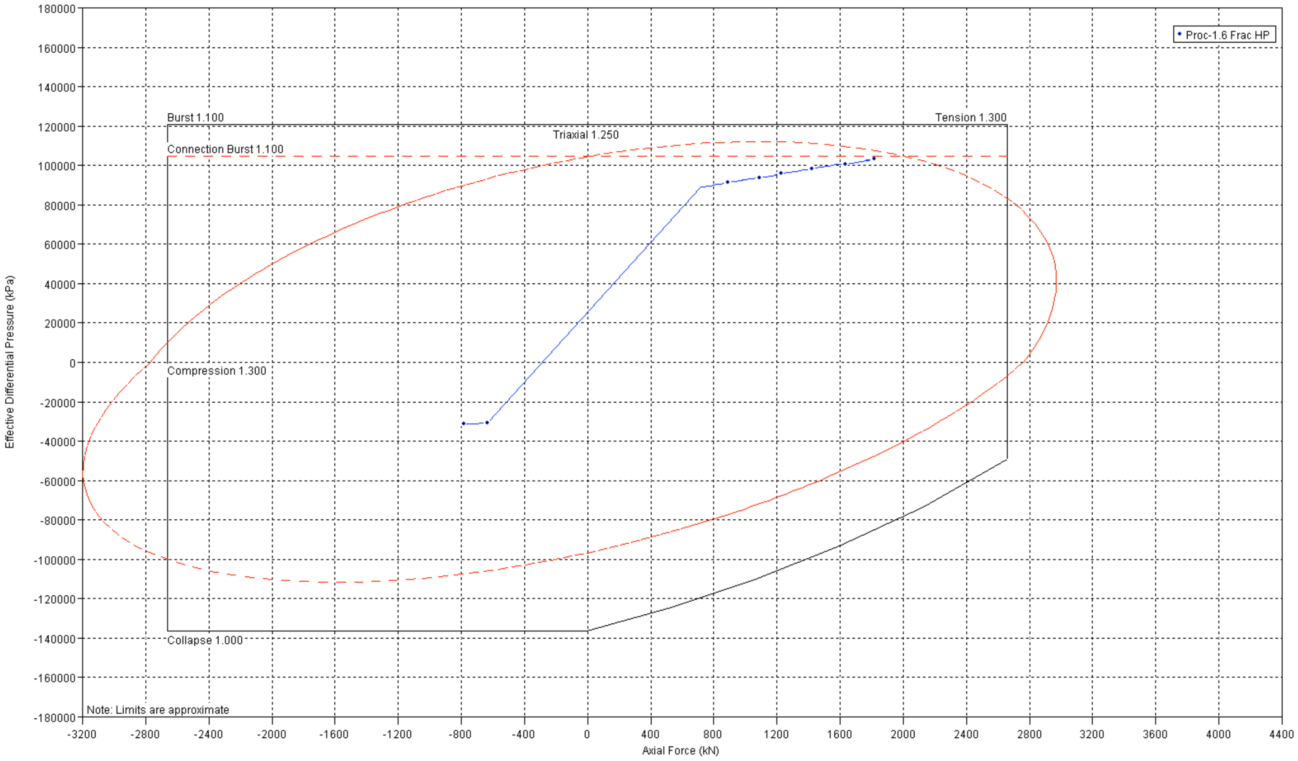


Fig.- 6-14 Maximum fracture pressure for tubing, 1150 bar.

Temperature

The temperatures of the injected fluid play a major role in the design analysis. The initial injection temperature is set to be 10 °C. It is the case of bullheading that first introduce a cold fluid to the warm well, so when fracture fluid is injected the well has already been cooled down and will cool down further. The fracturing fluid has been altered, both compositional and temperature wise to see how it will affect the tubing.

The fracturing fluid that was used for the initial case had a density of 1600 kg/m^3. The density was kept constant, while the temperature was increased to 100°C and 200°C. The result of this temperature change is shown in Fig.- 6-15.

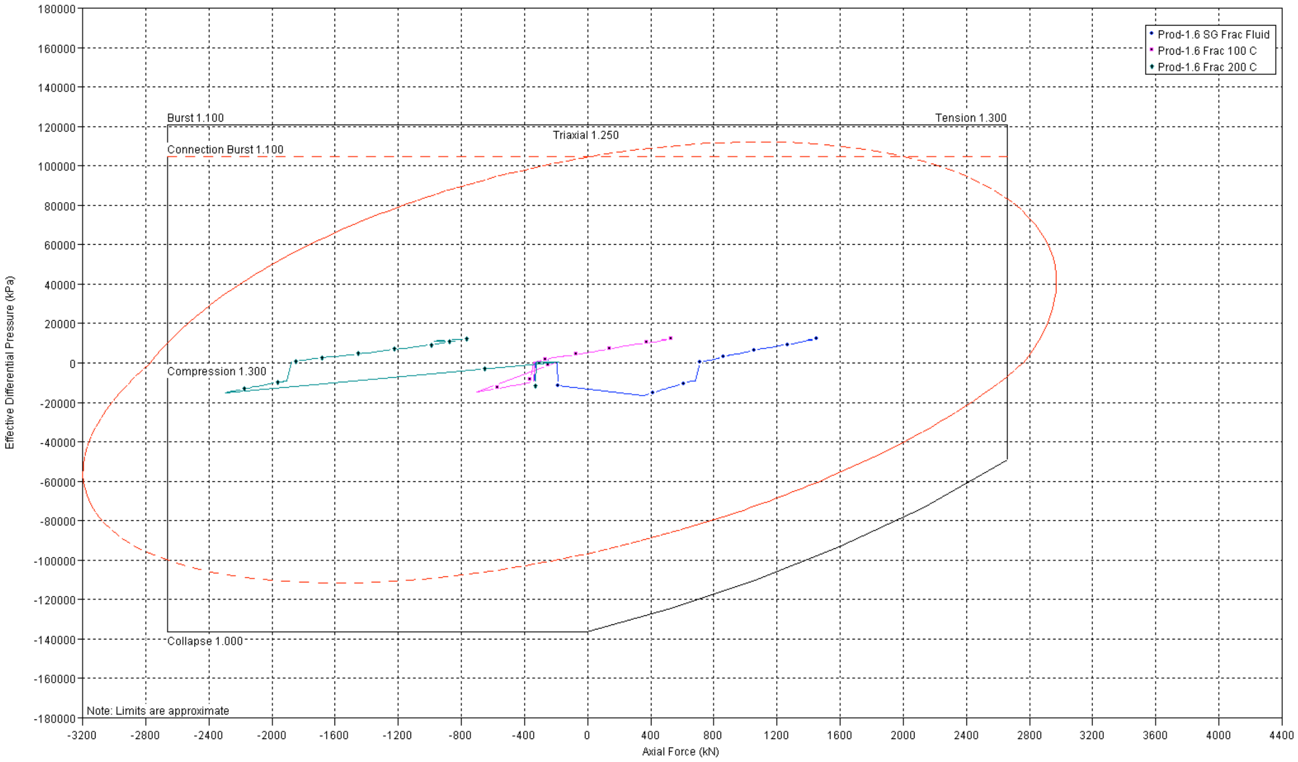


Fig.- 6-15 Design limit plot - Fracture fluid temperatures.

As seen for the figure, the rapid heating of the tubing will lead to high compression forces, this is because the tubing material expands due to the heat and creates a compressional force towards the tubing.

Tubing-to-packer force; Fracturing

The fracturing fluid is injected after bullheading of the well. The temperature of the well after the breakdown is 35 °C. The base case for hydraulic fracturing of the well is done by a fracturing fluid at 10 °C

As seen form Fig.- 6-16, the temperature inside the tubing has been heated to 31.4 °C, while the temperature in the annulus above the packer is 67.9 °C. Temperature has decreased from the breakdown load. Heat has been transferred from the warm tubing to the fracturing fluid, resulting in a warmer fluid and a cooler pipe. The result of this is that the tubing will try to contract as the metal cool down, as described in Appendix A.4.6. This will lead to an upward pull between tubing and packer. The tubing-to-packer force is in the upward direction, and has a value of 527.6 kN. The pressure below the packer is lower than the pressure in the annulus above the packer, the resulting force is in the downward direction.

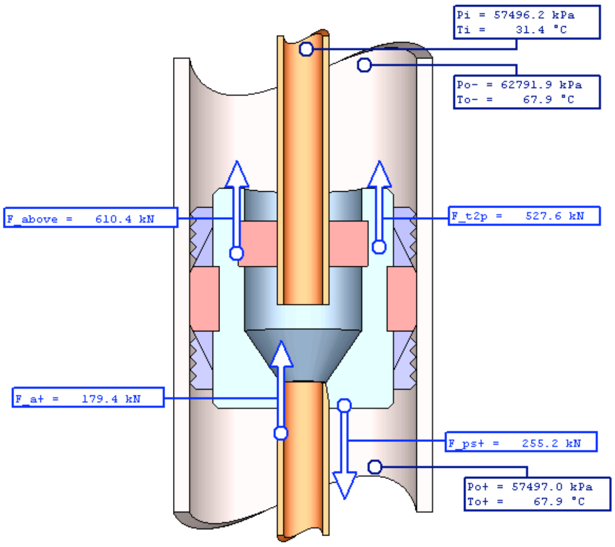

Pi = 57496.2 kPa
Ti = 31.4 °C
Po- = 62791.9 kPa
To- = 67.9 °C
F_above = 610.4 kN
F_t2p = 527.6 kN
F_a+ = 179.4 kN
F_ps+ = 255.2 kN
Po+ = 57497.0 kPa
To+ = 67.9 °C

Fig.- 6-16 Tubing-to-Packer force, fracturing base case.

If, for some reason the temperature of the fracturing fluid is increased to 100 °C the tubing temperature at packer depth is 106.1 °C. The injection of the hot fluid will also affect the temperature of the annulus, heating the packer fluid to 114.2 °C. This heating of the tubing material leads to an elongation of the tubing that contributes to the increased downward tubing-to-packer force. The tubing-to-packer force is 395.5 kN in the downward direction.

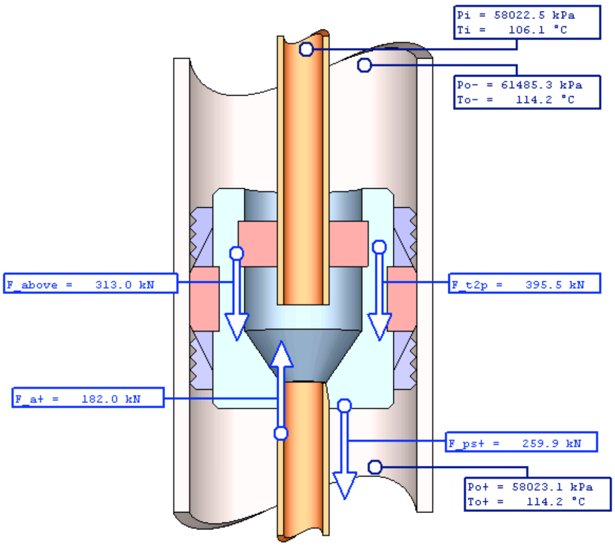

Pi = 58022.5 kPa
Ti = 106.1 °C
Po- = 61485.3 kPa
To- = 114.2 °C
F_above = 313.0 kN
F_t2p = 395.5 kN
F_a+ = 182.0 kN
F_ps+ = 259.9 kN
Po+ = 58023.1 kPa
To+ = 114.2 °C

Fig.- 6-17 Tubing-to-packer force, Fracturing at 100 °C.

7 Discussion

Based on the simulations done in Wellcat™, the completion design that has been chosen for K-14 has proven to stay intact during all the load scenarios that are planned for the well in its lifetime.

The completion configuration, with an open section between the liner and the tubing, and the production packer set in 9 5/8″ intermediate casing, is done because of the required flexibility for later perforation of the 7″ liner. All the equipment exposed in this area has to withstand all the same loads as the tubing. It is especially important that the 9 5/8″ intermediate casing is able to withstand the stress. If this casing bursts, the well integrity is at stake. Above the 9 5/8″ casing there is no mechanical barrier to stop any migration fluids under pressure, the only possibility to stop well fluids from escaping to surface is if the 9 5/8″ casing is set in a strong formation with a fracturing pressure higher than the reservoir pressure. As described in Appendix A.7, the production packer is placed as close to the reservoir as possible, but at a depth where the formation pressure is higher than maximum well pressure. This means that if there is a failure in 9 5/8″ casing, the formation pressure will ensure the well integrity.

When injecting cold fracturing fluid, the tubing will contract. When warm fluid is produced after fracturing, the metal will warm up and expand. This will create a large movement in the tubing and packer area. If the completion had not been able to handle the increased pressure variations, the design had to take a different approach, e.g. a PBR (polished bore receptacle) and associated seal assembly could be installed. In HPHT this is not the normal design, as a PBR is a potential leak path.

The exposed casings and liners will endure the planned load exposures. This was achieved by selecting a suitable material grade for pipes and connections. The design plot shows how the pipes react to each load (tension/compression, burst/collapse), and as seen from the results, the selected pipe and connections grade seems to be right: no load is outside of any of the limits, and the ellipse is not too "big" compared to the loads. This means that the metal selected is of sufficient quality, but also not too high. Selecting a grade that is too low will lead to failure, while selecting a grade that is overqualified will add unnecessary cost.

The selection of pipe material is important in relation to erosion and corrosion during the lifetime of the well. For a complete well design, the fluid properties of the produced and injected fluids are modelled and evaluated with the materials planned for the well to find corrosion rates. From this work the materials is determined. For K-14, the material chosen for the tubing is Super Chrome, which is known to be suitable for HPHT wells and is the same material used in the Morvin HPHT field. For HPHT conditions material is often determined to be on the safe side.

Wellcat™ is a complex software tool, used by most operators to model loads on the equipment installed in the wells. Each operator has their own governing documentation, which would imply minor differences in regulations for well design. E.g. safety factors/ design factors can be different for one operator to another. It is the most advanced software used in drilling and completion operations due to its built in features like modelling effects on temperature change to the near wellbore area from the planned operations. This is important for the HPHT well, where the forces and effects from the large change in temperatures are significant. For most operators, Wellcat™ is the only approved software for modelling HPHT well designs.

The software tool has a user interface that is not always intuitive and may affect the outcome. Wellcat™ users face the challenge of how to use the program correct; what input values are needed, where to give the correct input values, knowing and understanding the information that can be extracted, etc. And there is always the possibility of human errors when importing data from one source to another.

8 Conclusion

1. Forming K-14 to be as a typical well on Morvin; depth, temperature, well path and completion solution were set close to identical. The difference is that the K-14 well has been made to accommodate stimulation by hydraulic fracturing.

2. The difference between K-14 and a typical well on Morvin triggered a full well design review, discussing all aspects related to the equipment exposed to the extreme loads during fracturing and producing for a field with HPHT conditions.

3. An overview of the loads the well will be exposed to in its lifetime was made, and these were modelled in Wellcat™ with the field conditions for K-14. The results indicate a HPHT well design that can accommodate fracturing.

4. To debate the challenges often met in forming a well design and to show the implications and complexity of modelling that follows the requirements set to wells in a field development, the production packer is set in 9 5/8″ casing and a possible later perforation is enabled. This well design exposes the 9 5/8″ casing below the packer, the 7″ and 5″ liners to the extreme production and stimulation loads. These loads and their implications have been modelled, discussed and solved for K-14 in Wellcat™.

5. All the work with the development of the well design for K-14 is part of the well integrity of the well. A separate chapter discussing this was made to give an overview of the work done to ensure proper well integrity is maintained through all phases of K-14's life – including P & A.

9 Further work

The simulations done for K-14 have been based on well design and string analysis for tubing, part of the casings and liners, as well as for the production packer. All loads for a tubing design has been investigated. Further work required for the well design of K-14:

1. Obtain a more detailed formation evaluation that can be used in the casing design regarding setting depths of casings, the required height of cement, etc. This can be used to ensure the well integrity.

2. Evaluate the need for sand control for the well and what solutions that can be implemented in the design.

3. For stimulation by hydraulic fracturing, a sensitivity analysis should be made to see the effects of other fluids used then the ones modelled in this thesis. Planning fracturing is complex, as a detailed fracturing design is required to know the exact fluids: their specific weight, volume, cooling effect, etc. In this thesis, only the lightest and the heaviest practical fluids were modelled.

4. In the completion, only the tubing and production packer were investigated. To complete the design for K-14, the next step would be to identify a TRSCSSV, tubing hanger and possibly a DHSG suitable for the HPHT conditions and loads identified for K-14.

5. A full casing deign would also be natural to conduct in Wellcat™, as this is one of the few softwares commercially available on the market capable to model HPHT conditions properly.

6. The information package received on the production packer is detailed, but it is for a different size than the well design for K-14. Obtaining the correct packer and analysing this should be done.

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10 Nomenclature

F	Force	[N]
P_{bh}	Bottom hole pressure	[Pa]
P_{wh}	Wellhead pressure	[Pa]
OD	Outer diameter	[m]
ID	Inner diameter	[m]
A_s	Cross section, tubing	[m^2]
ρ_f	Density, fluid	[kg/m^3]
N	Normal force	[N]
ε	Strain	[-]
ΔL	Length change	[m]
L	Length of tubing	[m]
σ	Stress	[N/m^2]
E	Modulus of Elasticity	[N/m^2]
A_i	Internal cross section tubing	[m^2]
A_o	External cross section tubing	[m^2]
P_i	Internal pressure tubing	[Pa]
P_o	External pressure tubing	[Pa]

TVD	True vertical depth
MD	Measured depth
GOR	Gas Oil Ratio
DLS	Dogleg severity
TRSCSSV	Tubing retrievable surface controlled subsea safety valve
CWA	Corrosion wear allowance
PBR	Polished bore receptable
P & A	Plug and Abandonment
DHSG	Down hole safety gauge

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Appendix

A.1 Elements in Field Development

Seismic Acquisition

To get an overview of what's hiding underneath the seabed a seismic survey is done. On the Norwegian Continental Shelf a marine seismic vessel tows long streamers with hydrophones attached. The vessel is equipped with guns that set off a charge that will generate a pressure wave that will propagate through the water and into the formations. Different formation layers will reflect the pressure waves, sending a signal back to the hydrophones, as seen in Fig.- 1-1. This signal will be recorded and stored and converted into a reflection model that can be interpreted. The model can give information about the extent and geometry of the reservoir, composition and fluid content. An example of how seismic data is modelled is shown in Fig.- 1-2, the figure is from the Sleipner field.

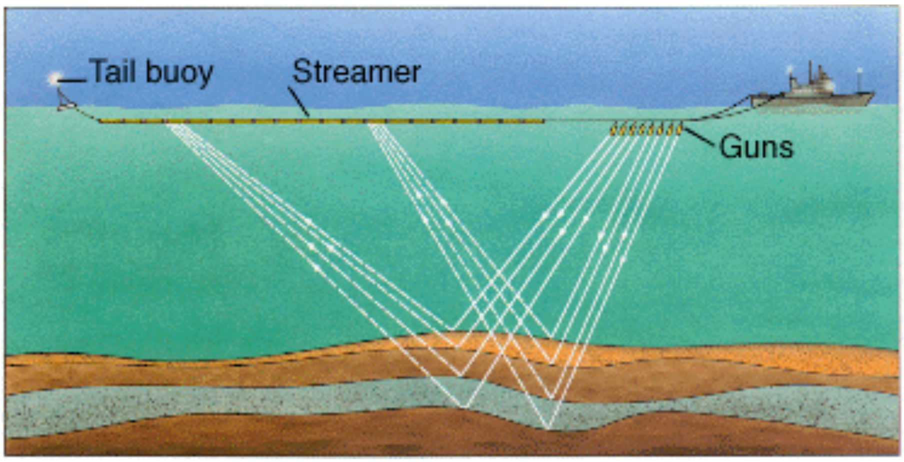

Fig.- 1-1 Marine seismic acquisition [Schlumberger 2012 A].

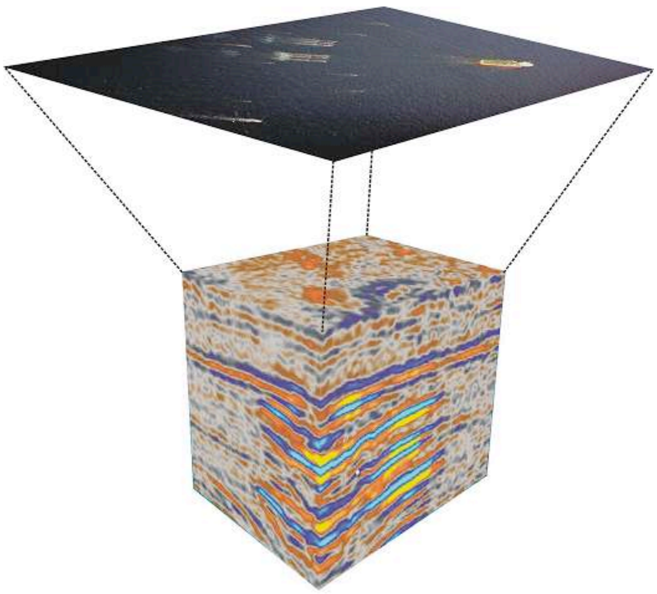

Fig.- 1-2 Seismic model [British Geological Survey 2012].

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Exploration Well

Based on the geological model developed after the seismic survey, an exploration well is drilled for further data collection. Different logging tools are sent down the well to measure and collect data. The simplest tool is the calliper tool that measures the borehole diameter. A reduced diameter can be a sign of porous and permeable formations due to the presence of mud cake or shale that has swollen. A larger diameter is caused by formation collapse because of poor consolidated sand or brittle shales. Other data gathered are lithology, porosity, water saturation, permeability and density [Glover 2012].

Reservoir Model

The reservoir model is based on a geological model and reservoir simulation models. The geological model provides a static description of the reservoir prior to production start, while the reservoir model simulates the fluid flow in the reservoir over the lifetime of production. The data collected from the seismic survey and the petrophysical data from the exploration well provides the input values for the model.

The reservoir evaluation has estimated the needed production rate for each well to maintain the planned plateau production. It is this rate that determines the required tubing diameter, and the hole and casing size are adjusted to fit the required tubing. For a HPHT well the dimensioning of the tubing does not only dependent on the required production rate, but also the extreme temperature and pressure conditions. If the planned tubing is not able to withstand all the extreme load cases it will be subjected to, the tubing design has to be reviewed and so has the whole production strategy. As an example, if the well needs to be completed with a 5 ½" tubing to maintain a certain production, but it turns out that this tubing is not suitable for the extreme conditions downhole and has to be replaced with a smaller diameter tubing. This might lead to less production from each well due to the reduced flow area, therefore the number of wells needed to deplete the reservoir has to be increased.

The economical aspect plays an important role in field development. The number of wells drilled has to be compared to each well's productivity to see if it is economically viable to drill. If the reservoir is located at great depth, high compaction may have lead to low permeability both horizontally and vertically. To increase the productivity for each well, the solution would be to increase the inflow area, the area where the well is in direct contact to the cell. A horizontal well is drilled, or highly deviated well is drilled to penetrate the length of the reservoir. This well is much more expensive to drill than a vertical, but the increased productivity may be able to defend the increased costs. When depleting a low permeability reservoir with horizontal wells, the number of wells required will decrease, defending the increased cost of each well.

Drilling and Well Management

Based on the information retrieved from the reservoir model the wells can now be designed. The well design is divided into two sections: drilling design and completion design. The completion is the interface between the reservoir and the surface production, and the main goal of the completion is to make the well safe and efficient. The drilling design has to be adapted to the completion of the well. The drilling crew's main tasks are to plan the casing program and perform the actual drilling of the well.

Field Development Plan

By Norwegian law a plan for development and operation (PUD) has to be developed and approved by the Petroleum Department if the licence holder of the petroleum deposit decides to develop the field. The plan has to include information about economical, resource, technical, safety- and environmental aspects. Information about how the equipment will be disposed after the field is abandoned shall be included, ad well as information about the facilities for transportation and utilization that are needed.

If petroleum deposits are discovered, the Ministry of Petroleum have the authority to decide that recovery of the resourced shall be prepared, commenced or continued if already developed. This is to be the case if it is economical viable, in terms of amount of hydrocarbons present and the possibility for an efficient transport system. If the licence holder decides to develop the field, a plan for development and operation has to be presented after two years. Is the licence holder decides not to develop, a report has to be presented that shows it is not economic viable to develop. If the license holder fails to deliver a report, or if they decide not to develop, the Ministry can take action and initiate or continue production, or revoke the license or part of it. [Lovdata 2003]

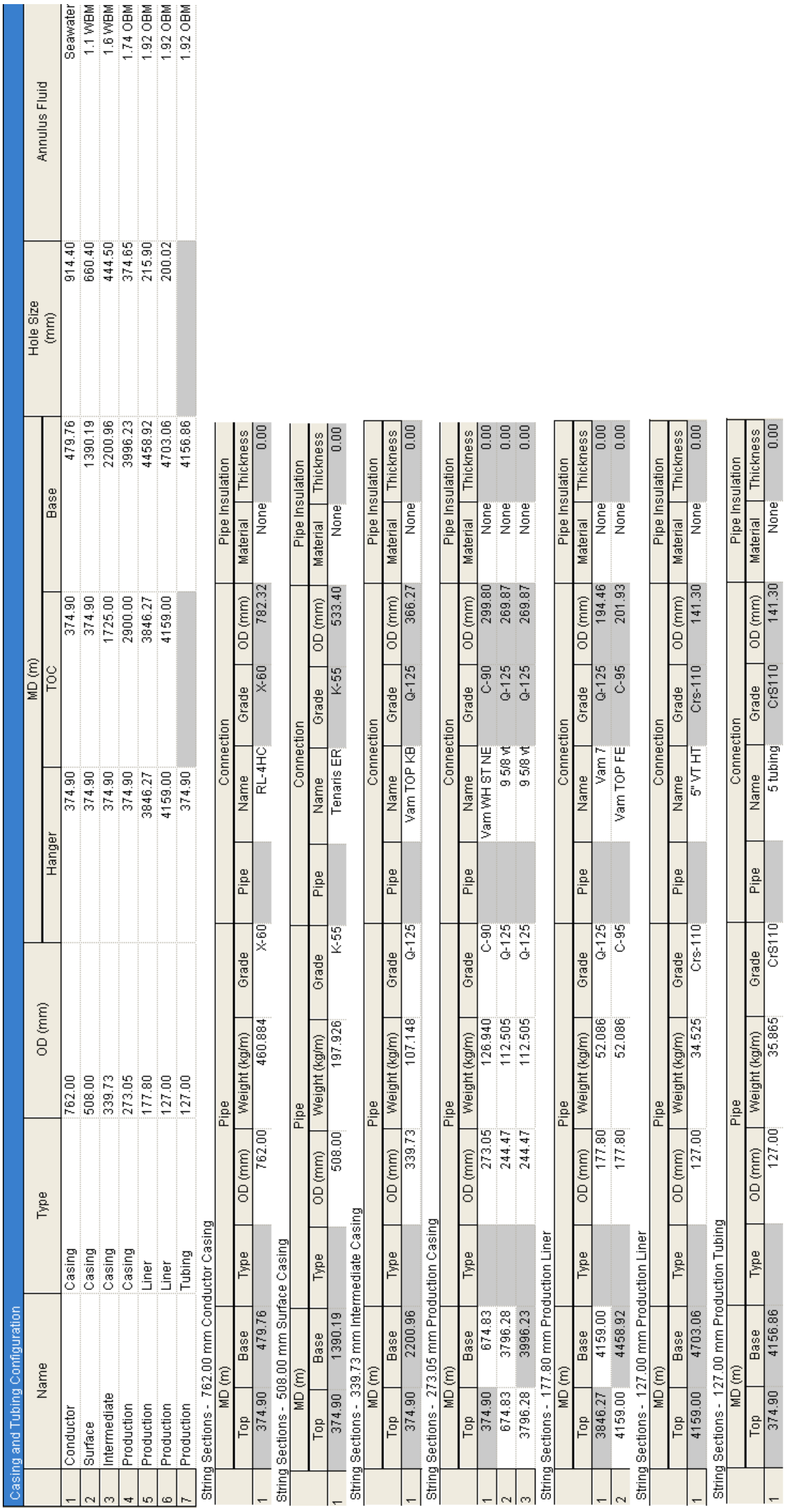
A.2 Gas composition

Table 2-1 Gas Composition

Component	Mole %
CO_2	2.90
H_2S	0.00
N_2	0.44
C1	59.15
C2	7.69
C3	5.18
NC4	2.23
IC4	0.97
NC5	1.11
IC5	0.86
NC6	1.44
C7+	18.03

A.3 Casing Design

An overview of the complete tubing, liners and casing design used in Wellcat™.



Casing and Tubing Configuration

	Name	Type	OD (mm)	MD (m)			Hole Size (mm)	Annulus Fluid
				Hanger	TOC	Base		
1	Conductor	Casing	762.00	374.90	374.90	479.76	914.40	Seawater
2	Surface	Casing	508.00	374.90	374.90	1390.19	660.40	1.1 WBM
3	Intermediate	Casing	339.73	374.90	1725.00	2200.96	444.50	1.6 WBM
4	Production	Casing	273.05	374.90	2900.00	3996.23	374.65	1.74 OBM
5	Production	Liner	177.80	3846.27	3846.27	4458.92	215.90	1.92 OBM
6	Production	Liner	127.00	4159.00	4159.00	4703.06	200.02	1.92 OBM
7	Production	Tubing	127.00	374.90		4156.86		1.92 OBM

String Sections - 762.00 mm Conductor Casing

	MD (m)		Pipe				Connection				Pipe Insulation	
	Top	Base	Type	OD (mm)	Weight (kg/m)	Grade	Pipe	Name	Grade	OD (mm)	Material	Thickness
1	374.90	479.76		762.00	460.884	X-60		RL-4HC	X-60	782.32	None	0.00

String Sections - 508.00 mm Surface Casing

	MD (m)		Pipe				Connection				Pipe Insulation	
	Top	Base	Type	OD (mm)	Weight (kg/m)	Grade	Pipe	Name	Grade	OD (mm)	Material	Thickness
1	374.90	1390.19		508.00	197.926	K-55		Tenaris ER	K-55	533.40	None	0.00

String Sections - 339.73 mm Intermediate Casing

	MD (m)		Pipe				Connection				Pipe Insulation	
	Top	Base	Type	OD (mm)	Weight (kg/m)	Grade	Pipe	Name	Grade	OD (mm)	Material	Thickness
1	374.90	2200.96		339.73	107.148	Q-125		Vam TOP KB	Q-125	366.27	None	0.00

String Sections - 273.05 mm Production Casing

	MD (m)		Pipe				Connection				Pipe Insulation	
	Top	Base	Type	OD (mm)	Weight (kg/m)	Grade	Pipe	Name	Grade	OD (mm)	Material	Thickness
1	374.90	674.83		273.05	126.940	C-90		Vam WH ST NE	C-90	299.80	None	0.00
2	674.83	3796.28		244.47	112.505	Q-125		9 5/8 vt	Q-125	269.87	None	0.00
3	3796.28	3996.23		244.47	112.505	Q-125		9 5/8 vt	Q-125	269.87	None	0.00

String Sections - 177.80 mm Production Liner

	MD (m)		Pipe				Connection				Pipe Insulation	
	Top	Base	Type	OD (mm)	Weight (kg/m)	Grade	Pipe	Name	Grade	OD (mm)	Material	Thickness
1	3846.27	4159.00		177.80	52.086	Q-125		Vam 7	Q-125	194.46	None	0.00
2	4159.00	4458.92		177.80	52.086	C-95		Vam TOP FE	C-95	201.93	None	0.00

String Sections - 127.00 mm Production Liner

	MD (m)		Pipe				Connection				Pipe Insulation	
	Top	Base	Type	OD (mm)	Weight (kg/m)	Grade	Pipe	Name	Grade	OD (mm)	Material	Thickness
1	4159.00	4703.06		127.00	34.525	Crs-110		5" VT HT	Crs-110	141.30	None	0.00

String Sections - 127.00 mm Production Tubing

	MD (m)		Pipe				Connection				Pipe Insulation	
	Top	Base	Type	OD (mm)	Weight (kg/m)	Grade	Pipe	Name	Grade	OD (mm)	Material	Thickness
1	374.90	4156.86		127.00	35.865	CrS110		5 tubing	CrS110	141.30	None	0.00

A.4 Mechanics

There are several load scenarios that will affect the tubing design of this well. The well is a production well, and therefore the main focus has been on stress analysis related to production and stimulation.

A.4.1 Axial Loads

Axial loads are loads that work on the length of the tubing, either by compression or tension. Factors that affect these loads are tubing weight, pressure and temperature variation. Many of the load types lead to length change in the tubing, which will weaken the material's capacity to take further loads.

A.4.2 Hydrostatic Forces

When an object is submerged in a fluid hydrostatic forces will act on the cross section of the object. In this case, the cross section, A_s, is at the bottom of the tubing string where the hydrostatic pressure is highest. The pressure at this point is given in **Eq.** (4.2).

$$F_{hydrostatic} = A_s P_{bh} \tag{4.1}$$

$$P_{bh} = P_{wh} + \rho_l g TVD \tag{4.2}$$

$$A_s = \frac{\pi}{4}(OD^2 - ID^2) \tag{4.3}$$

A.4.3 Hooks Law

When an element is exposed to tensile or compressional forces the result will be a deformation of the element. This deformation is given by **Eq.** (4.4) and represents the length change relative to the total length of the unloaded element.

$$\epsilon = \frac{L - L_0}{L_0} = \frac{\Delta L}{L_0} \tag{4.4}$$

Normal stress is the normal force divided by the cross sectional area, as shown in **Eq.** (4.5).

$$\sigma = \frac{N}{A} \tag{4.5}$$

The relationship between normal stress and axial strain is called Hooke's Law and is given by **Eq.** (4.6)**.** [Irgens 2006 A]

$$\sigma = E\varepsilon \tag{4.6}$$

A.4.4 Neutral stability point

The tubing will experience its axial load either as tension or compression. The top part of the tubing will bear the whole weight of the tubing, this is where the tension is greatest, but it will decrease with depth. The point of neutral stability is where the load switches from tension to compression, where the tubing is in equilibrium.

The neutral stability point can be described by **Eq.** (4.7) [Azar et al. 2007].

$$F_z = P_i A_i - P_o A_o \tag{4.7}$$

Where

F_z is the true axial force
P_i is the internal pressure on the tubing
A_i is the cross sectional area of the ID
P_o is the external pressure on the tubing
A_o is the cross sectional area of the OD

If both sides of the equation are equal, then the sting is at its equilibrium, if the axial force is greater then the string will be straight. Buckling may occur below the neutral stability point if the force is greater that what the pipe can tolerate. The neutral stability point is illustrated in Fig.- 4-3.

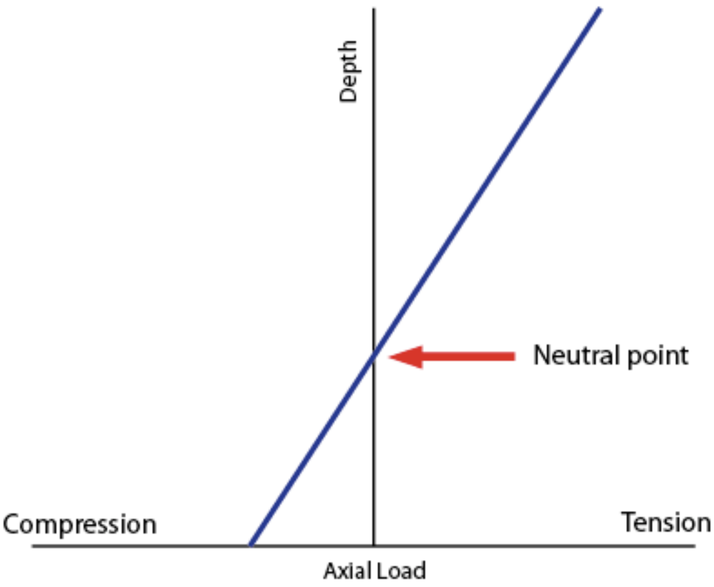


Fig.- 4-3 Neutral stability point, modified from Wellcat™.

A.4.5 Ballooning

The axial tension that may apply to the tubing does not only generate axial strain, but also a radial compression strain. It is this radial strain that is referred to as ballooning.
If a higher pressure is applied to the inside of the tubing it will create an axial tensile force, this will cause the tubing to shrink if able to move freely. Opposite case, if the highest pressure is applied outside the tubing it will cause axial compression, which will cause the tubing to elongate if able to move freely. This force is expressed as

$$F_b = 2\mu(A_i \Delta p_i - A_o \Delta p_o) \tag{4.8}$$

After the production packer is set, the tubing will be fixed in both ends. In the case of axial tension, the tubing will try to contract which leads to expansion of the tubing in the radial direction, as seen at the left side in the figure below. The opposite case with axial compression is called reverse ballooning and will cause the tubing to contract in the radial direction, as seen on right hand side in the Fig.- 4-4.

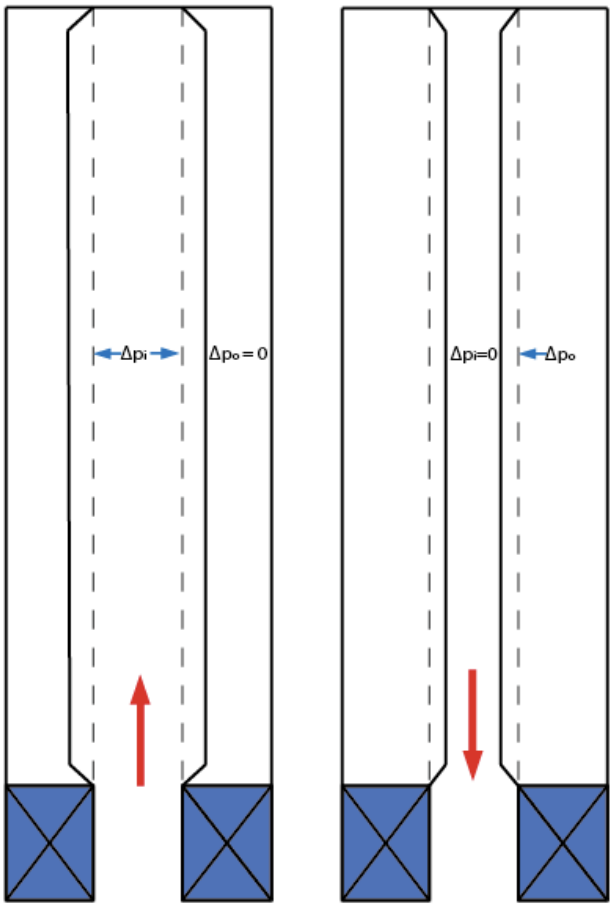


Fig.- 4-4 Ballooning and Reverse Ballooning

If the tubing were free to move, the length change caused by ballooning would be ΔL_{BAL} and is shown by **Eq.** (4.9).

$$\Delta L_{BAL} = \frac{-2\mu L}{E(A_o - A_i)}(\Delta p_i A_i - \Delta p_o A_o) \qquad (4.9)$$

where μ is the relationship between radial strain and axial strain and are related by **Eq.** (4.10). [Bellarby, 2009]

$$\mu = -\frac{Radial\ strain}{Axial\ strain} \qquad (4.10)$$

A.4.6 Temperature

Temperature changes in the well can have large effect on the tubing. If metal is heated it will expand, and the length expansion (ΔL_T) is given by **Eq.** (4.11).

$$\Delta L_T = C_T \Delta T L \tag{4.11}$$

C_T is the coefficient of thermal expansion and is material dependent. When choosing material, temperature changes that may appear in the well has to be taken into consideration.

If the tubing is fixed in both ends, heating will make the material expand and create a compressional force. Likewise, if cooling takes place, the material will contract and a tensile force will apply to the tubing. The force that applies is given in **Eq.** (4.12) below. [Bellarby, 2009]

$$F_T = -C_T E \Delta T (A_o - A_i) \tag{4.12}$$

A.4.7 Buckling

Buckling is often associated with a long and thin element, in this case the tubing string. If there is a small existing bend in the tubing there will be possibility for it to develop further when pressure is applied. The area of the outside of the bend will be greater than on the inside, so when in compression and internal pressure is greater than external the chance of buckling will increase. The opposite case of greater external pressure and tension will reduce the chance of buckling. The effect of axial load (F_{total}) and pressure on the tubing leads to **Eq.** (4.13**)** and the cross section areas used are shown in Fig.- 4-5**.**

$$F_{eff} = F_{total} + (p_o A_o - p_i A_i) \tag{4.13}$$

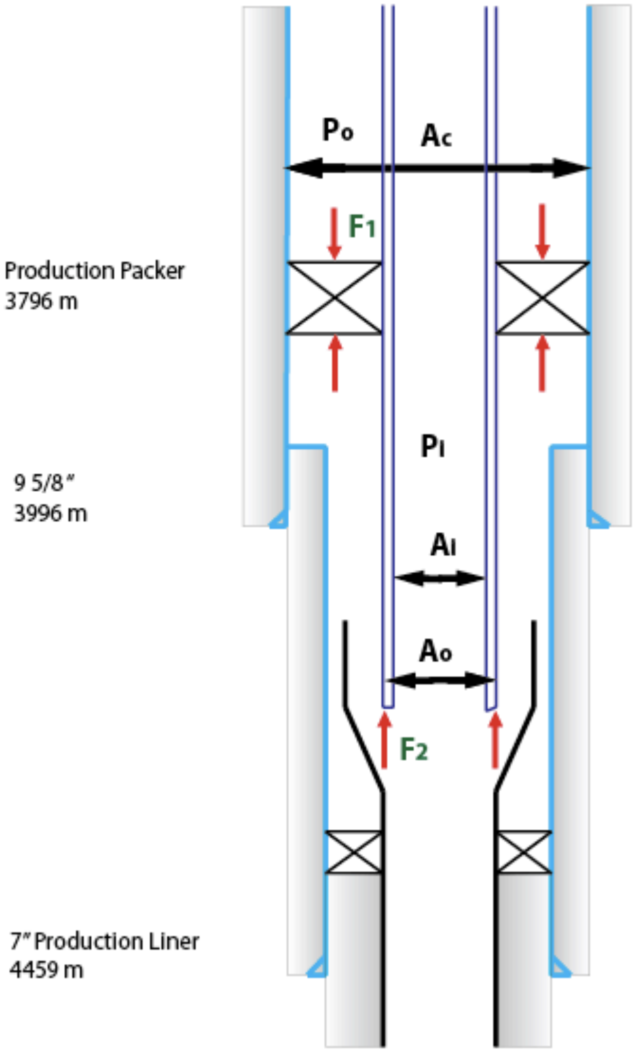

Po
Ac
F1
Production Packer
3796 m
Pi
9 5/8"
3996 m
Ai
Ao
F2
7" Production Liner
4459 m

Fig.- 4-5 Tubing cross section.

There are two types of buckling, sinusoidal buckling and helical buckling. For a deviated well the critical force of buckling is given by **Eq.** (4.14) for sinusoidal and **Eq.** (4.15) for helical. In the deviated end of the well, the tubing has to be lifted up (overcome gravity) before sinusoidal buckling can occur. When half way up the walls, helical buckling will take over.

Sinusoidal buckling:

$$F_c = \sqrt{\left(\frac{4EIw\sin\theta}{r_c}\right)} \qquad \textbf{(4.14)}$$

Helical buckling:

$$F_c = 1.41{\sim}1.83\sqrt{\left(\frac{4EIw\sin\theta}{r_c}\right)} \qquad \textbf{(4.15)}$$

For buckling to occur the negative value of the critical force (F_c) has to be greater than the effective tension (F_{eff}). This is summarized in Table 4-2 below.

Table 4-2 Requirements for buckling. Modified from [Bellarby, 2009].

Situation	Outcome
$F_{eff} < -F_c$	Tubing will buckle
$F_{eff} > -F_c$	Tubing will not buckle

The length change due to buckling is expressed by **Eq.** (4.16**)** [Mitchell 1999], and will lead to shortening of the tubing.

$$\Delta L_b = -\frac{r^2}{8EIw}\left[{F_2}^2 - {F_1}^2\right] \tag{4.16}$$

Where:

r = radial clearance between casing ID and tubing OD

E = Youngs modulus

I = Moment of interia = $\frac{\pi}{64}\left({d_o}^4 - {d_i}^4\right)$, where d_o = OD tubing and d_i = ID casing

w = Axial distributed load in the tubing

$F_2^2 - F_1^2$ = Effective axial force at the bottom of the tubing.

A.4.8 Burst

If the internal pressure of the tubing is much higher than the external pressure in the annulus then the yield strength of the tubing will be set to a test. The API burst rating for a thin-walled pipe is given by the formula:

$$p_b = Tol\left(\frac{2Y_p t}{D}\right) \tag{4.17}$$

where Tol is the reduction of wall thickness tolerance fraction (12.5 % reduction for API pipe), Y_P is the yield strength of the pipe, t is the nominal tubing thickness and D is the outside diameter of the tubing. [Bellarby, 2009]

For burst failure to occur, only a small piece of the tubing needs to fail. The smallest variation of the minimum wall thickness will have an impact on the burst rating, and for tubing the major problem is related to corrosion.

A.4.9 Collapse

The collapse rating is more complex to establish than burst rating because it is an instability problem requiring the yield of the whole tubing and all the way around. Rating is dependent on tubing diameter, wall thickness and the ovality of the pipe. There have been defined four different collapse modes, depending on the D/t ratio: elastic, transitional, plastic and yield strength. Elastic collapse (equation (4.18)) has the highest ratio, while yield collapse has the lowest ratio, depending on tubing grade. [Bellarby, 2009]

Elastic collapse:

$$p_e = \frac{46.95 \times 10^6}{(D/t)[(D/t) - 1]^2} \tag{4.18}$$

Transitional collapse:

$$p_t = Y_p \left(\frac{F}{D/t} - G \right) \tag{4.19}$$

Plastic collapse:

$$p_p = Y_p \left[\frac{A}{D/t} - B \right] - C \tag{4.20}$$

For the transitional and plastic collapse the values for A, B, C, F and G are supplied by API 5C3 [API Bull. 5C3 1999] via formula or from table, taking consideration to material grade.

In the case of external pressure is much higher than the internal pressure of the tubing yield collapse is induced.

Yield collapse:

$$p_y = 2Y_p \left[\frac{(D/t) - 1}{(D/t)^2} \right] \tag{4.21}$$

This way of calculating (API 1999 and earlier) the yield collapse is very conservative and can lead to unnecessary expensive pipes in a high pressure well. A new way to calculate the yield was developed in 2008 (Payne, 2001), but these formulas require measurement and control of parameters like ovality, eccentricity and residual stress. To overcome the gap between the two ways of calculating the collapse rating, high collapse tubing has been developed. [Bellarby, 2009]

A.4.10 Triaxial

The combination between axial stress, tangential stress and radial stress is what makes up triaxial stress **(**Fig.- 4-6**)** It is the effect of having both external pressure and tension or the combination of internal pressure and compression that will generate higher stress than either of the pressure or axial loads alone.

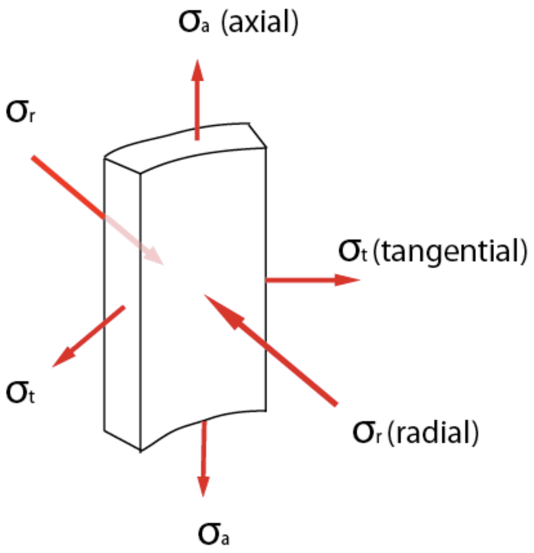


Fig.- 4-6 Stress components of triaxial analysis.

The most used criterion for determining triaxial stress is the Huber-Hencky-Mises yield condition (4.22**)**.

$$\sigma_{VME} = \frac{1}{\sqrt{2}}[(\sigma_a - \sigma_t)^2 + (\sigma_t - \sigma_r)^2 + (\sigma_r - \sigma_a)^2]^{0,5} \qquad (4.22)$$

The radial and tangential stress can be calculated from Lamé's equations.

Radial stress:

$$\sigma_r = \frac{p_i A_i - p_o A_o}{(A_o - A_i)} - \frac{(p_i - p_o) A_i A_o}{(A_o - A_i) A} \qquad (4.23)$$

Tangential Stress:

$$\sigma_t = \frac{p_i A_i - p_o A_o}{(A_o - A_i)} + \frac{(p_i - p_o) A_i A_o}{(A_o - A_i) A} \qquad (4.24)$$

If a plane stress condition is assumed, σ_r is set to be zero. This will reduce **Eq.** (4.22) down to **Eq.** (4.25). [Irgens 2006 B].

$$Y_p = \sqrt{{\sigma_a}^2 + {\sigma_t}^2 - \sigma_a \sigma_t} \tag{4.25}$$

When plotting the triaxial criterion in the design limit plot, it is possible to compare it to the design stresses of the tubing and its connections. If the triaxial stress is greater than the yield strength for the materials used, then there will be yield failure. The principle of a design limit plot for a pipe is shown in Fig.- 4-7.

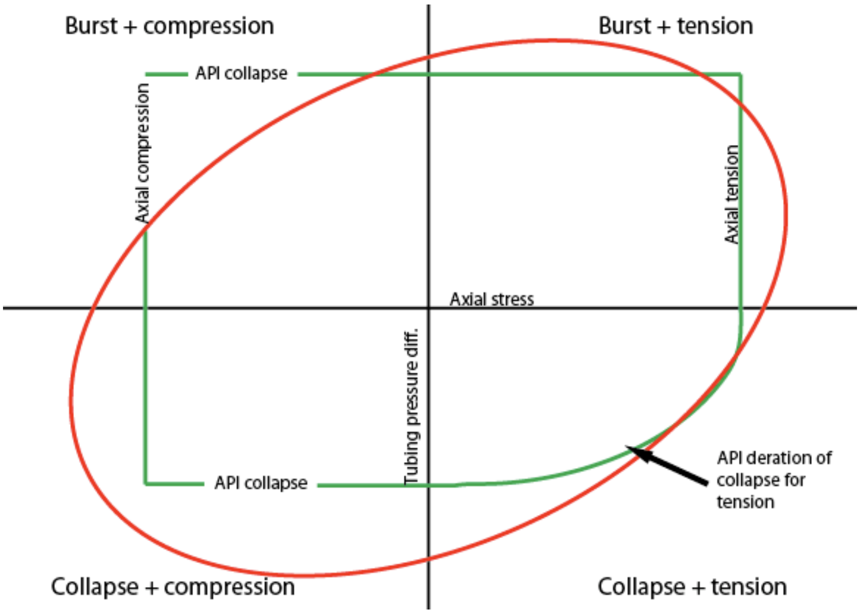

Burst + compression
Burst + tension
API collapse
Axial compression
Axial tension
Axial stress
Tubing pressure diff.
API collapse
API deration of collapse for tension
Collapse + compression
Collapse + tension

Fig.- 4-7 Design limit plot. Modified from [Bellarby, 2009].

A.5 WELLCAT™

The software that has been used to perform tubing calculations is Wellcat™ from Landmark. The software has five working modes, but for this thesis and its tubing string calculations Prod mode and Tube mode has been used.

”The Prod Design module simulates fluid and heat transfer during completion, production, stimulation, testing and well servicing operations.” - [Halliburton 2012 A]. Production loads like clean up, production, shut in, kill, fractioning etc. have been defined in this mode.

”The Tube Design module analyses tubing loads movements, buckling behavior and design integrity under complex mechanical, fluid pressure and thermal loading conditions with standard and automatic load-case generation.” - [Halliburton 2012 A]. Both Prod defined loads and loads defined in Tube Mode are calculated here.

The loads that are described in Wellcat™ are only a snapshot of the situation with the given wellhead pressure and fluid density. The input of a previous operation makes it possible for Wellcat™ to calculate the temperature gradients and how they change from one operation to another.

Inventories

In order to do the simulations the inventories that are specific for the well has to be defined. Some of the inventories used for this well are default values defined in the template file in Wellcat™. The ones that have been user defined for this well are described in more detail below the list.

- Fluids
- Pipes
- Drill string
- Heat conduction properties
- Coiled tubing
- Grade properties
- Temperature deration
- Proprietary connections
- Bit sizes
- Formation properties
- Cement properties
- Tubing filters

Well survey

This is not defined as an inventory, but it is important input values that are specific to each well. The first that is done when opening a new file is to import well survey, where measured depth, true vertical depth, dogleg severity, azimuth etc. give Wellcat™ the possibility to draw the planned well path. Pore pressure and fracture pressure are defined relative to the depth. As a simplification, the temperature gradient is given as a linear function.

Pipes and Connections

For the pipe design, several pipe grades and material qualities are standard in the inventories list, if a different grade is required this has to be entered. The same goes for the pipe connections. After the pipe grade and material has been defined, type of pipe (drill pipe or HWDP) and size can be defined. The pipes used for casing and tubing are from the same inventory list.

Fluids

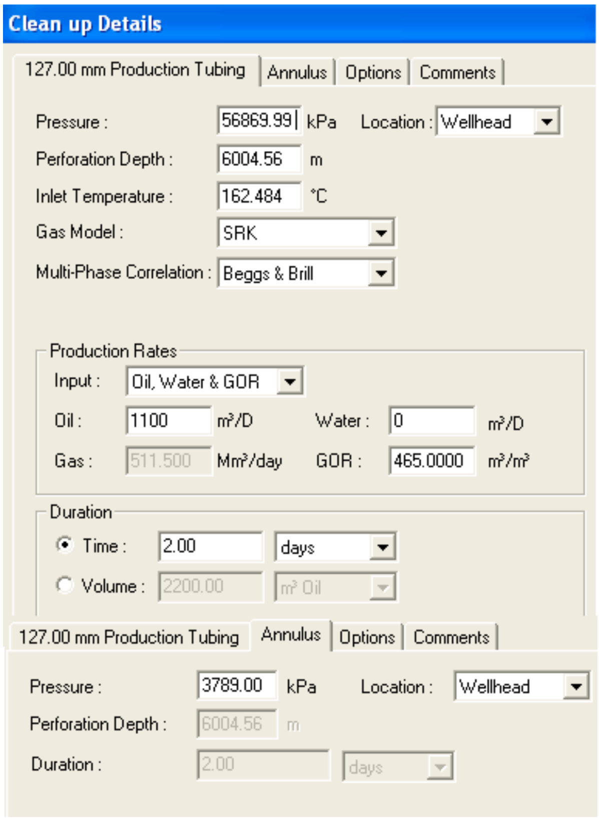
Different operations in the well require fluids that are developed to function at an optimum at the specific operation. The fluids that have been defined for this well are standard hydrocarbons, muds, brines and polymers. Default values have been used for cement.

A.6 Loads

A.6.1 Clean up – first flowing of the well

Before the well start to produce the well has to be cleaned out to remove remaining cuttings and drilling fluid, this is done by producing hydrocarbons through the production tubing at full production rate. A good clean up is important to avoid future complications like setting of plugs, packers and premature setting of packers.
The clean up lasts for two days and operate with a supporting annulus pressure. During this period the tubing and surroundings are heated up with warm production stream. Wellcat™ only register pressure and temperature, so it does not detect cuttings and different compositional fluids, like well completion fluid, therefore the loads will be much the same as for early production.

As the well first start to produce the space between the area between the production packer and top of the 5" liner will be filled with fluid. There will be little circulation and replacement of this fluid as the well is producing, so there is a minimum amount of corrosion in this area.



Pressure : 56869.99 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Inlet Temperature : 162.484 °C
Gas Model : SRK
Multi-Phase Correlation : Beggs & Brill

Production Rates
Input : Oil, Water & GOR
Oil : 1100 m^3/D Water : 0 m^3/D
Gas : 511.500 Mm^3/day GOR : 465.0000 m^3/m^3

Duration
● Time : 2.00 days
○ Volume : 2200.00 m^3 Oil

Annulus
Pressure : 3789.00 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Duration : 2.00 days

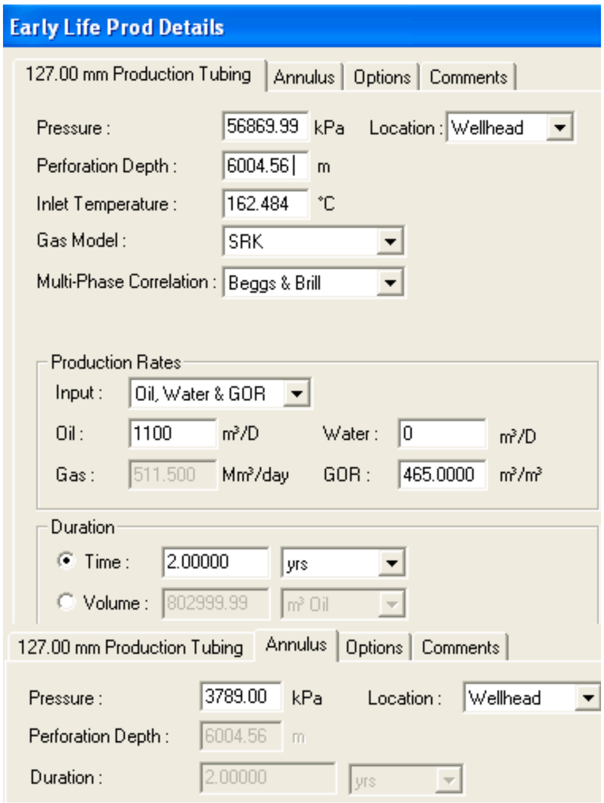
The wellhead pressure is calculated to be the pore pressure at perforations subtracting the hydrostatic column of the hydrocarbon fluid that is in the well. The density of the reservoir fluid was calculated to be 632 kg/m^3. The temperature is estimated form the given temperature gradient. Annulus pressure is set to be equal to the hydrostatic column of seawater on top of the wellhead, this is done to get maximum pressure differential between tubing and annulus.

A.6.2 Early life production

This is the time in the life of the well where production rate is the highest. The well has a lifetime of approximately 16 years, and it has been assumed that early life production last for two years. In this period the reservoir pressure is 837 bar at perforations, the production rate is 1100 Sm^3/D and the gas-oil rate is 465 Sm^3/m^3. The annulus is shut in and has a hydrostatic pressure equal to the fluid present.

Early life production is based on prior operation to be clean up. As mentioned, this means that the well has already been exposed to the warm production stream, so there will not be a significant temperature change in the well.

In complete well design mid life- and late life production is also taken into consideration, but for this thesis it has been assumed that early life production is the case where tubing is exposed for the highest loads, and has therefore been used as prior operation to several of the following load cases.



Early Life Prod Details

127.00 mm Production Tubing | Annulus | Options | Comments

Pressure : 56869.99 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Inlet Temperature : 162.484 °C
Gas Model : SRK
Multi-Phase Correlation : Beggs & Brill

Production Rates
Input : Oil, Water & GOR
Oil : 1100 m^3/D Water : 0 m^3/D
Gas : 511.500 Mm^3/day GOR : 465.0000 m^3/m^3

Duration
● Time : 2.00000 yrs
○ Volume : 802999.99 m^3 Oil

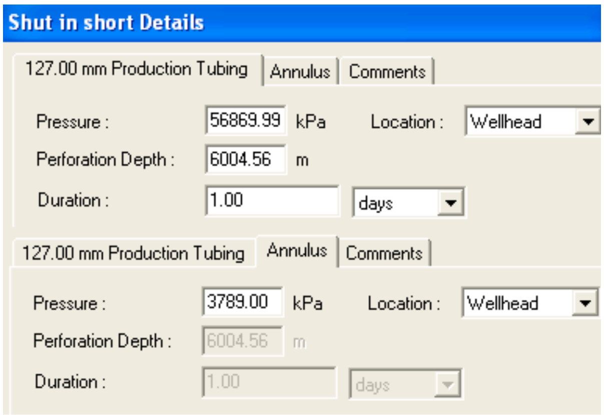
127.00 mm Production Tubing | Annulus | Options | Comments

Pressure : 3789.00 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Duration : 2.00000 yrs

The wellhead pressure and the temperature are the same as for the clean up operation. The early life production is set to last for two years, Wellcat™ will simulate the temperature change. The annulus pressure is set to be hydrostatic column of seawater.

A.6.3 Shut in Short

A shut in is when the production from the well is stopped to do maintenance on the well, the duration of the short shut in period is set to be one day. The shut in is based on early life production with high pressure and production rates, and both the production tubing and the annulus are shut in. The pressure in the tubing is set to be maximum wellhead pressure at shut in, and the annulus pressure is set to be the hydrostatic pressure of the packer fluid. As there is no flow in the tubing the temperature will drop, but not significant because of the short shut in time.


Shut in short Details

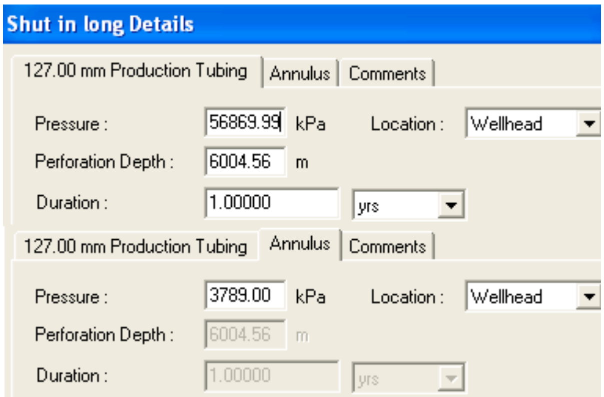
Pressure : 56869.99 kPa
Location : Wellhead
Perforation Depth : 6004.56 m
Duration : 1.00 days

Pressure : 3789.00 kPa
Location : Wellhead
Perforation Depth : 6004.56 m
Duration : 1.00 days

The shut in wellhead pressure is the same as for early life production. Annulus pressure is set to hydrostatic column of seawater.

A.6.4 Shut in Long

Shut in long is based on the parameters and the result of shut in short. The duration of the shut in period is set to be one year, and give way to do major maintenance of the well. When there is no longer a warm production stream flowing through the tubing the tubing will gradually cool down, and formation will return to ambient temperature. A sudden start up of production will lead to a great temperature difference between the producing fluid and the cold tubing. The internal and external pressure will be the same as for shut in short. The cooling of the tubing will be greater for this load case, but not significant for the strength of the tubing.


Shut in long Details

Pressure : 56869.99 kPa
Location : Wellhead
Perforation Depth : 6004.56 m
Duration : 1.00000 yrs

Pressure : 3789.00 kPa
Location : Wellhead
Perforation Depth : 6004.56 m
Duration : 1.00000 yrs

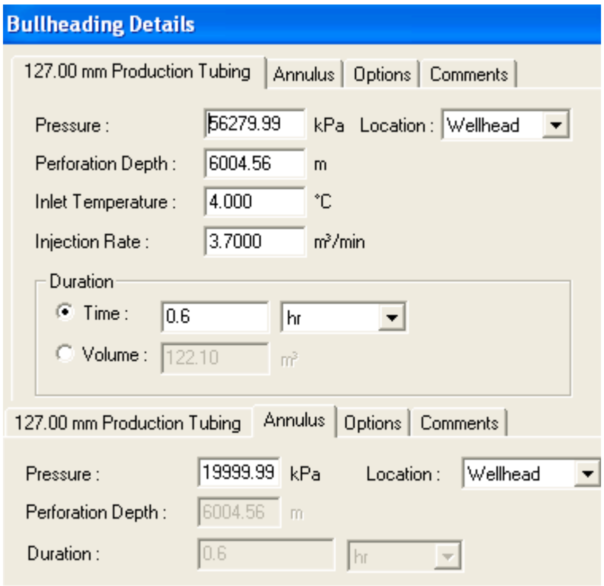
Both wellhead and annulus pressure is the same for shut in long as for shut in short. The duration is one year, which leads to greater cooling of the tubing. Annulus pressure is set to hydrostatic column of seawater.

A.6.5 Bullheading

Since the well is located offshore, there is an unlimited supply of seawater and this is used for the injections. The density used for seawater is 1030 kg/m^3 and that will give a hydrostatic pressure of 475 bar at perforations. The injected fluid will force hydrocarbons back into the formation. This operation is often used if it is suspected that the formation fluids contain toxic hydrogen sulfide, or if normal circulation cannot occur due to fore example a borehole collapse. The method is used when it is important to quickly get the well under control, and there is no time to set up a proper circulation system to kill the well.

In the Wellcat™ simulation, bullheading is following early life production where reservoir pressure is 837 bar. The job start by displacing the hydrocarbon that is already present in the tubing, before more seawater is injected. The pump pressure needed for the injection will be highest at the start because of the light hydrocarbons occupying the tubing. As more seawater is injected, the required pump pressure will decrease because of the hydrostatic pressure of the seawater contribute more to the downhole pressure. The load case that has been calculated in Wellcat™ is when the tubing is completely filled with the injected fluid, this is the same for all the injection cases.

The pressure loss due to friction along the tubing and through the perforations has to be overcome. It has been done a simple assumption that the pressure loss due to this is 10 psi/100 ft, which is 2.26 bar/100 m [Brechan 2012]. In addition a safety margin of 35 bar has been added on top of this to include uncertainties to when the rock will fracture.
The minimum required displacement rate needed to account for gas migration is 1 m/sec. Two tubing volumes are to be injected into the well in about 30 minutes. To finish the bullhead within this time, the injection rate has to be increased to 3,7 m^3/min.


Bullheading Details
127.00 mm Production Tubing
Annulus
Options
Comments

Pressure : 56279.99 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Inlet Temperature : 4.000 °C
Injection Rate : 3.7000 m³/min
Duration
● Time : 0.6 hr
○ Volume : 122.10 m³

127.00 mm Production Tubing
Annulus
Options
Comments

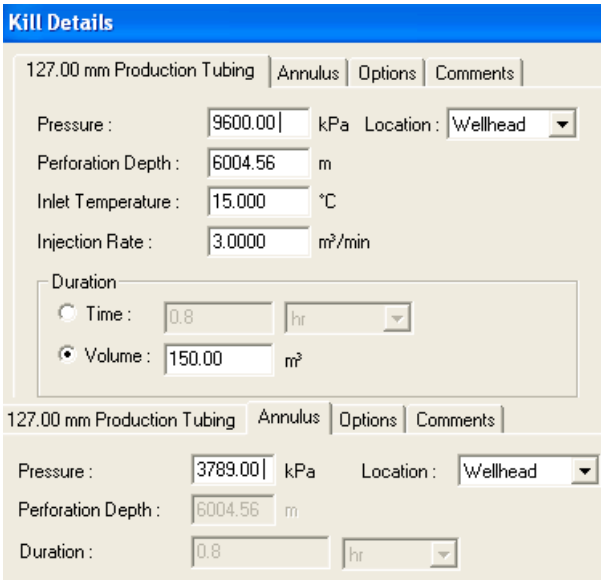
Pressure : 19999.99 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Duration : 0.6 hr

Tubing is filled with seawater. Wellhead pressure is calculated by subtracting the hydrostatic column of the tubing fluid and the assumed pressure drop from the pore pressure. On top of this friction pressure drop and a safety margin of 35 bar has been added. It is assumed that the temperature of the seawater injected is somewhat lower than other injected and processed fluids, temperature is therefore set to 4°C. Annulus pressure is set to 200 bar.

A.6.6 Kill operation

The main concerns related to kill operations are the start of the kill and the end of the kill. At the start the wellhead pressure is high and the fluid injected is hot, at the end the pressure is low, but cooling is significant. [Bellarby, 2009]

To kill the well a higher density fluid is injected into the well. The fluid that is used in the simulation is a $CaCl_2$-$CaBr_2$-$ZnBr_2$ brine with a density of 2061 kg/m^3. The hydrostatic pressure with this fluid is 950 bar, which is higher than reservoir pressure and will therefore be able to prevent formation fluids from flowing into the well. The pump pressure required will only be the pressure loss due to friction and the safety margin of 35 bar on top of that. The velocity requirement is the same as for bullheading, but only one tubing volume needs to be injected.


Kill Details
127.00 mm Production Tubing
Annulus
Options
Comments

Pressure : 9600.00 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Inlet Temperature : 15.000 °C
Injection Rate : 3.0000 m³/min
Duration
○ Time : 0.8 hr
● Volume : 150.00 m³

127.00 mm Production Tubing
Annulus
Options
Comments

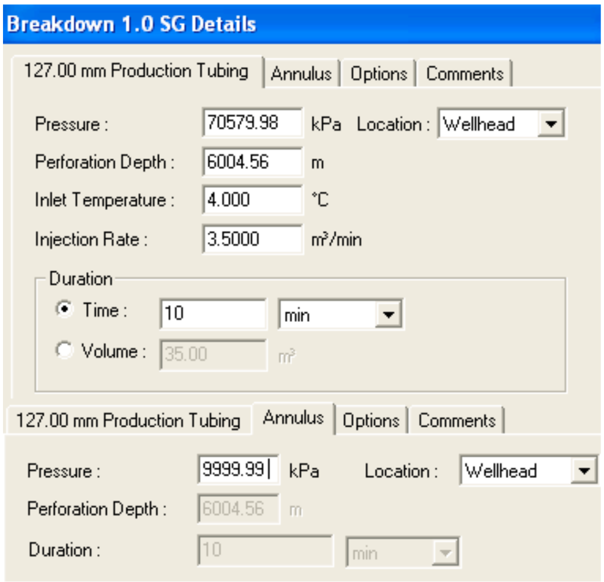
Pressure : 3789.00 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Duration : 0.8 hr

The wellhead pressure needed for this operation is lower than for bullheading because a higher density fluid is used. Otherwise, the same procedure for calculating pressure has been used. The temperature has been set to 15°C. Annulus pressure is set to hydrostatic column of seawater.

A.6.7 Breakdown

Breakdown pressure is when the rock formation fractures and allows fluids to be injected into the formation. To establish the accurate breakdown pressure, a fluid is pumped down the well. At the start of the injection the tubing is filled with the previous operations bullheading fluid (seawater). This is the same as fluid as used during breakdown.

Since the tubing is already filled with seawater from previous operation, the duration will only be for a short period. The pump pressure that needs to be applied is breakdown pressure of the formation (formation fracture pressure + 60 bar safety factor) minus the hydrostatic pressure of the seawater plus a safety factor of 35 bar and pressure loss along the tubing.



Breakdown 1.0 SG Details

Pressure : 70579.98 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Inlet Temperature : 4.000 °C
Injection Rate : 3.5000 m³/min
Duration
● Time : 10 min
○ Volume : 35.00 m³

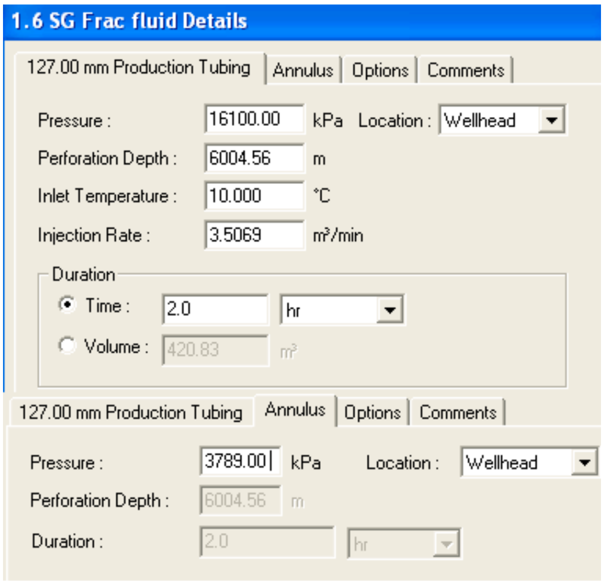
Annulus:
Pressure : 9999.99 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Duration : 10 min

The same inlet temperature as for bullheading has been used. Annulus pressure is set to 200 bar.

A.6.8 Fracturing

Following the breakdown is the actual fracturing of the well. In this case a fluid with a density of 1600 kg/m^3 is pumped into the formation to create fractures into the reservoir. The fluid also contains proppants that will flow into the fractures and keep them open after the stimulation job is done. The annulus shut in during this operation, and the annulus pressure is equal to the hydrostatic pressure of the fluid present.

The wellhead pump pressure is to be calculated in the same way as for the breakdown case. The formation fracture pressure is assumed to be 950 bar at perforations, but since fracturing is following the breakdown on the formation, the pressure required is 70% of the pressure needed to break down, this gives a fracturing pressure of 707 bar that has to be overcome.


1.6 SG Frac fluid Details

127.00 mm Production Tubing | Annulus | Options | Comments

Pressure : 16100.00 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Inlet Temperature : 10.000 °C
Injection Rate : 3.5069 m³/min
Duration
● Time : 2.0 hr
○ Volume : 420.83 m³

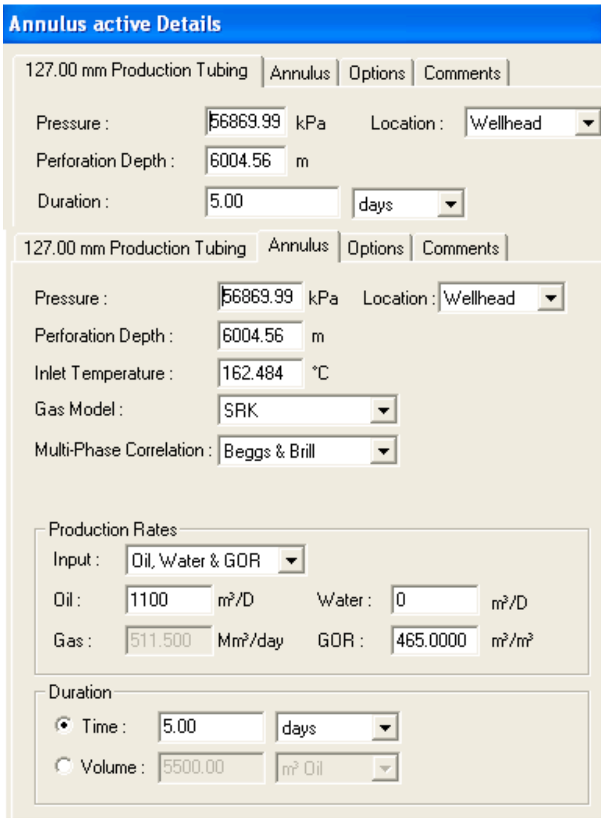
127.00 mm Production Tubing | Annulus | Options | Comments

Pressure : 3789.00 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Duration : 2.0 hr

The wellhead pressure is calculated by subtracting the hydrostatic column of the fracturing fluid and adding the frictional pressure drop and the safety margin of 35 bar. Annulus pressure is set to hydrostatic column of seawater.

A.6.9 Annulus Active

During this operation the production tubing is shut in, leading the production stream through the annulus. The prior conditions for this operation is a undisturbed well, so no production has gone through the tubing prior to this load test. The wellhead pressure input is the same on both sides of the tubing.


Annulus active Details

127.00 mm Production Tubing | Annulus | Options | Comments

Pressure : 56869.99 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Duration : 5.00 days

127.00 mm Production Tubing | Annulus | Options | Comments

Pressure : 56869.99 kPa Location : Wellhead
Perforation Depth : 6004.56 m
Inlet Temperature : 162.484 °C
Gas Model : SRK
Multi-Phase Correlation : Beggs & Brill
Production Rates
Input : Oil, Water & GOR
Oil : 1100 m³/D Water : 0 m³/D
Gas : 511.500 Mm³/day GOR : 465.0000 m³/m³
Duration
● Time : 5.00 days
○ Volume : 5500.00 m³ Oil

Wellhead pressure and annulus pressure is equal to maximum shut in pressure calculated the same way as clean up, early life production, etc. Early life production rates are produced through annulus.

A.6.10 Initial Conditions

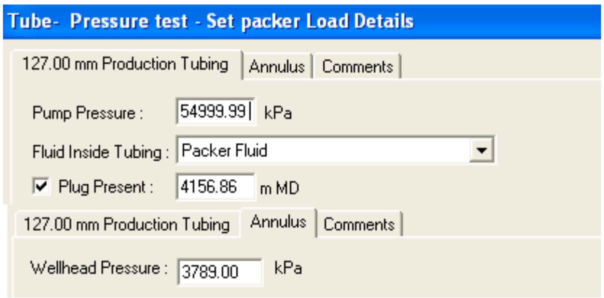
In this case no external loads are applied to the tubing, the only load that is implemented is the axial force acting on the tubing. This is a pre-defined load scenario in Wellcat™, therefore no simulation environment has been entered. It is important that all input parameters are correct, since all other load scenarios are calculated relative to this. The tubing will experience the highest tension load at the top, since this part of the tubing has to hold the weight of the tubing below. Tension will decrease gradually further down the well and will switch overt to compression at the bottom of the well.

A.6.11 Pressure Test

The highest load that the well has to be dimensioned for is the pressure test. This is to ensure that the well can withstand any load that it is subjected to during its lifetime. This is good practise because the tubing is often considered as a well barrier. It is a good margin to dimension the completion to withstand a pressure test that is 10 % above maximum tubing differential pressure during service loads. The load scenario should be shut-in case or an injection case. [Bellarby, 2009]

Set packer

The pressure is applied at the wellhead on top of the fluid that is present in the well. There is a plug at the end of the tubing, and the pressure below the plug is calculated according to the hydrostatic column. The annulus pressure is equal to the hydrostatic column of the fluid present. An undisturbed temperature profile is assumed.


Tube- Pressure test - Set packer Load Details

Pump Pressure : 54999.99 kPa

Fluid Inside Tubing : Packer Fluid

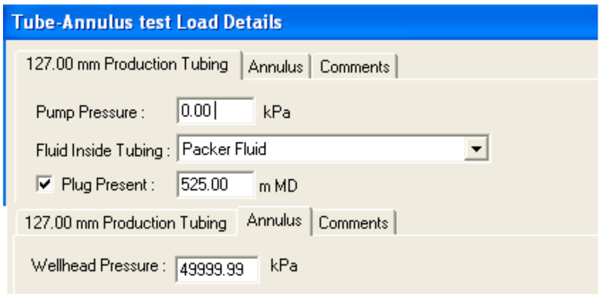
☑ Plug Present : 4156.86 m MD

Wellhead Pressure : 3789.00 kPa

Pump pressure is adjusted so that the differential pressure will be the greatest of all the loads. Annulus pressure is set to hydrostatic column of seawater.

Annulus

The main purpose of an annulus pressure test is to test packer and tubing hanger. In this pressure test the tubing pressure is set to be equal the hydrostatic column of fluid present, so no pump pressure is applied at the wellhead. The annulus wellhead pressure is set to be 500 bar. An undisturbed temperature profile is assumed.



Tube-Annulus test Load Details

Pump Pressure : 0.00 kPa

Fluid Inside Tubing : Packer Fluid

☑ Plug Present : 525.00 m MD

Wellhead Pressure : 49999.99 kPa

The annulus is pressure tested by applying 500 bar at top of annulus. Pump pressure is set to be zero, Wellcat™ include hydrostatic pressure from seawater.

A.6.12 Tubing Leak

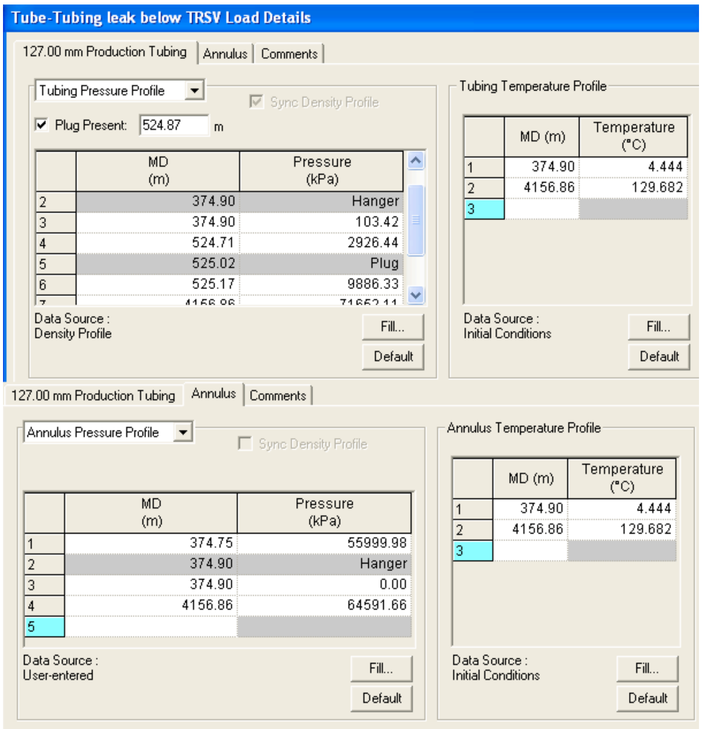
In the case of tubing leak, the pressure will be equalized so that it is the same on both sides of the tubing where the leak is detected.

Below Tubing Hanger

This load case is based on early life production, and recalls all the loads related to that stage. Tubing pressure is applied to the annulus at the surface, this can lead to severe pressure in annulus at packer depth which can result in high collapse loads. The load is pre defined in Wellcat™ tube mode.

Below closed TRSV

This load is custom designed in Wellcat™. In this case there is a leak below the closed plug that is set at 525 meters. The pressure above the plug is bleed off to hydrostatic pressure, and below the plug the pressure is equal to the shut in pressure at the given depth. Annulus pressure is equal to shut in pressure on top of the hydrostatic column. Tubing temperature profile is linked to early production, which will be one of the scenarios with the highest temperature exposure, an exception may be injection of a warmer fluid for well treatment.



Tube-Tubing leak below TRSV Load Details

Tubing Pressure Profile

☑ Sync Density Profile

☑ Plug Present: 524.87 m

	MD (m)	Pressure (kPa)
2	374.90	Hanger
3	374.90	103.42
4	524.71	2926.44
5	525.02	Plug
6	525.17	9886.33
7	4156.86	71662.11

Data Source : Density Profile

Tubing Temperature Profile

	MD (m)	Temperature (°C)
1	374.90	4.444
2	4156.86	129.682
3		

Data Source : Initial Conditions

Annulus Pressure Profile

☐ Sync Density Profile

	MD (m)	Pressure (kPa)
1	374.75	55999.98
2	374.90	Hanger
3	374.90	0.00
4	4156.86	64591.66
5		

Data Source : User-entered

Annulus Temperature Profile

	MD (m)	Temperature (°C)
1	374.90	4.444
2	4156.86	129.682
3		

Data Source : Initial Conditions

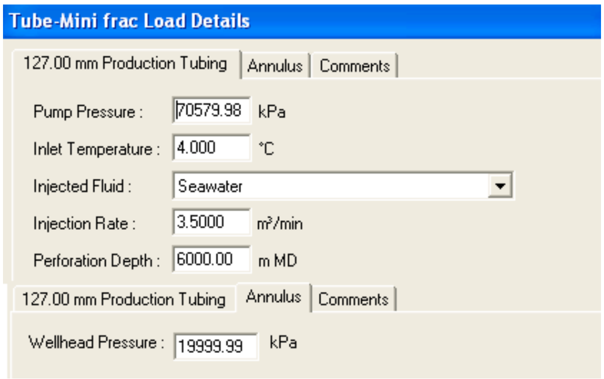
A.6.13 Tubing Evacuation

This load will simulate worst case scenario where the tubing is filled with air, leading to zero surface pressure. It is really a severe collapse test of the tubing [Wellcat™ Manual 2001]. The temperature profile is based on early life production. The annulus pressure is set to 37.89 bar, which is equal to the hydrostatic pressure of the seawater above.

Because of the high GOR for this well, opening the well to atmospheric pressure will more likely lead to evacuation of the gas, leaving only dead crude in the well. But if the liquid level of crude left in the well is below the base of the tubing, it will practically be the same as assuming full evacuation. [Bellarby, 2009]

A.6.14 Mini-fracturing

This is a transient injection of a fluid that only lasts for a short time period (in this case seawater has been injected for 30 minutes). The injection pressure is the same as for early stage injection following breakdown, which has an injection pressure of 705.8 bar.



Tube-Mini frac Load Details

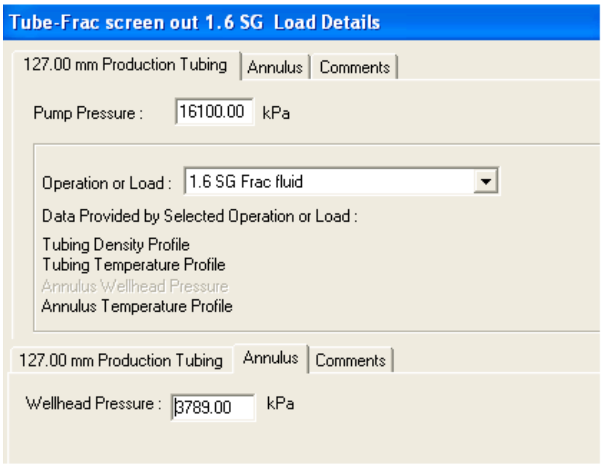
Pump Pressure : 70579.98 kPa
Inlet Temperature : 4.000 °C
Injected Fluid : Seawater
Injection Rate : 3.5000 m³/min
Perforation Depth : 6000.00 m MD

Wellhead Pressure : 19999.99 kPa

Pump pressure is set to be the same as for the breakdown load because seawater has been used for injection. Annulus pressure is set to hydrostatic column of seawater.

A.6.15 Screen out

Screen out is when injection of fracture fluid leads to blockage of perforations. When this happens there is a rapid decrease in fluid flow, which leads to a sudden increase in pump pressure. The prior operation to this load is the fracturing with 1.6 SG fracture fluid. The pump pressure is the same as for the fracture case, 161 bar.



Tube-Frac screen out 1.6 SG Load Details

Pump Pressure : 16100.00 kPa

Operation or Load : 1.6 SG Frac fluid
Data Provided by Selected Operation or Load :
Tubing Density Profile
Tubing Temperature Profile
Annulus Wellhead Pressure
Annulus Temperature Profile

Wellhead Pressure : 3789.00 kPa

This load is pre-defined in Wellcat™, pressure and fluid had been inserted. Pump pressure is the same as for the initial fracturing load. Annulus pressure is set to hydrostatic column of seawater.

A.7 Packer

The production packer seals off the annulus between the production tubing and the casing, and is set as close to the bottom of the tubing, and above the top perforations. It is locked into place by metal wedges called slips that dig into the casing. The actual sealing is completed by a large rubber element, and in the case of the pressure exceeding 345 bar, metal rings are used on either side of the rubber elements to support and prevent collapse of the seal.

The placement of the production packer should be as close to the reservoir as possible and at a depth where the cemented casing can withstand the pressure of the well. In case of low penetration when drilling through this area, the drill string may have worn the casing, so it is also important that the casing exposed in this area has acceptable casing wear. In case of casing and cement failure, the shallowest allowable setting depth is where the formation still is strong enough to withstand maximum reservoir pressure.

For the K-14 well the production packer has been placed between the 9 5/8″ casing and the production tubing. It could have been placed closer to the reservoir in the 7″ liner, if that were the case the strength of the packer would be greater due to the smaller cross section. This solution was not selected because the possibility for drilling a sidetrack trough the 7″ would not be possible without changing of packer, and that would result in high costs related to new production packer required and time consuming operation.

In previous HPHT completions on the Kristin field it had been incidents of premature sets of permanent packers, this lead to the development of a new retrievable HPHT packer with anti-preset feature.

The packer selected for this completion is SB-3H Production Packer (Fig.- 7-8) developed by Baker Oil Tools based on the field proven SB-3 Retainer Production Packer [Baker Oil Tools 2008]. The packer was set hydraulically at 3796.28 m MD at an initial set pressure of 345 bar and a plug depth of 3840.48 m MD. The axial load change after packer set is 44.48 kN, and seal bore is present.

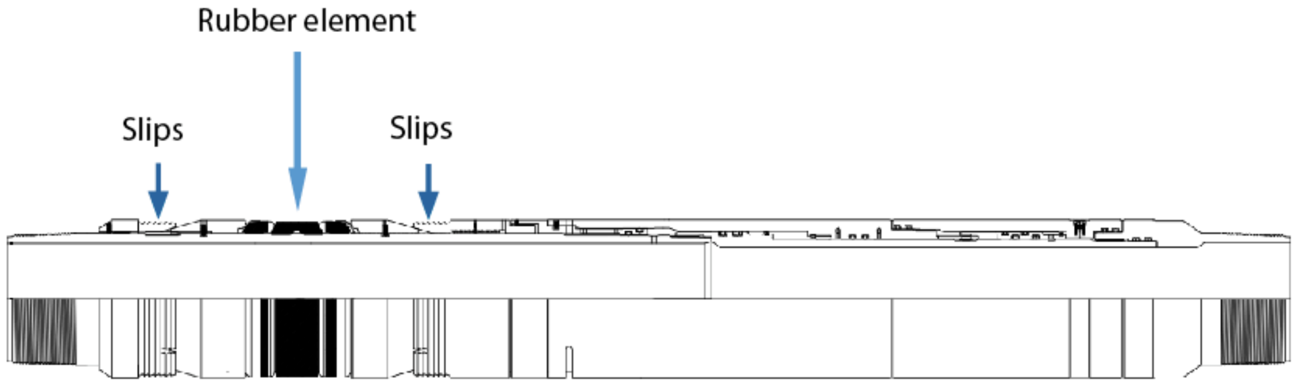


Fig.- 7-8 Production packer, drawing no. A28-993-00 [Baker Oil Tools 2008].

There are two ways to construct a packer envelope, either by testing or by calculations. The packers made by Baker Oil Tools are tested to its extreme to determine the design limit. This method is very reliable and can guarantee no failure. If the packer envelope is based on calculations there are no actual guarantee that it will work in a well situation with high differential pressures and varying temperatures. The advantage with calculated envelopes are that they can include both the pressure above and below the packer, compared to a packer that has been designed from testing that only sees the pressure from underneath the packer.

Following is a detailed evaluation of the tubing-to-packer forces that are calculated by Wellcat™. The pressure test load case has been used as an example to show the forces that affect the packer. For packers with seal bores the tubing to packer force is as follows:

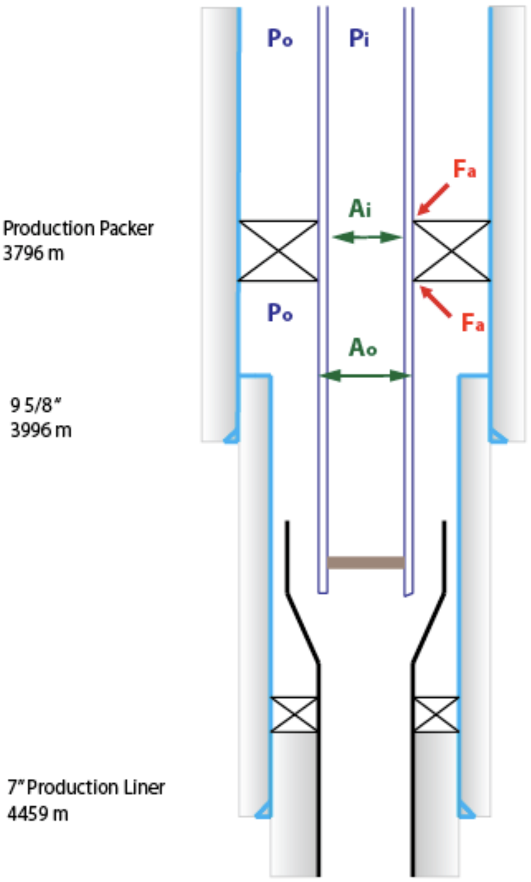

Po
Pi
Fa
Ai
Production Packer
3796 m
Po
Fa
Ao
9 5/8"
3996 m
7" Production Liner
4459 m

Fig.- 7-9 Tubing-to-packer forces, modified form Wellcat™.

$$F_{t2p} = F_{a+} - (A_{i+} - A_p)P_i + (A_{o+} - A_p)P_{o+} - F_{a-} + (A_{i-} - A_p)P_i - (A_{o-} - A_p)P_{o-} \qquad (7.26)$$

where:

- A_{o+}, tubing outside area below the packer
- A_{o-}, tubing outside area above the packer
- A_{i+}, tubing inside area below the packer
- A_{i-}, tubing inside area above the packer
- P_i, inside pressure
- P_{o+}, outside pressure below packer
- P_{o-}, outside pressure above packer
- F_{a+}, axial force below packer (tension is positive)
- F_{a-}, axial force above packer (tension is positive)

The above equation can be reduced to the following:

$$F_{t2p} = F_{above} - F_{tail} \tag{7.27}$$

where:

- F_{above} = $-F_{a-}$ (axial force above packer)
- F_{tail} = F_{a+} (axial force on tail pipe)

A.8 Well Integrity

Well integrity – "application of technical, operational and organisational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well". [NORSOK D-010 2004]

Sand Production

A rock mechanics study has been carried out for the Morvin well, and it concluded that sand control would not be required for the field. But since this is a fictive field and no rock evaluation has been performed it can be assumed that since the well is producing from a sand reservoir, there is a possibility for sand production. The wear and tear on pipes and equipment are to taken into consideration when designing the well. Whether sandscreens are installed or not, it is always important to continuously (or at least at a regular interval) monitor the amount of sand that is produced, either downhole, subsea or at surface. This will make it possible to estimate the effect it has on the equipment, and to evaluate the possibility for equipment failure.

Sand production through a perforated liner may lead to serious erosion of the tubing in the lower completion. By identifying the amount of sand produced by each layer, and locate the contributing zone, it is possible to install inflow control on the particular zone to minimize sand production and the erosion on equipment.

Scale

Scale formation in the well can lead to blockage or inoperable valves like the TRSCSSV. This is may be fatal to the primary barrier, if the TRSCSSV cannot close, only secondary barrier is left to prevent uncontrolled outflow. The produced and injected fluids have to be chemically analysed, and if there is a possibility of scale formation scale inhibitor or dissolver shall be established. A solution to this could be to install a chemical injection sub with dual check valves below the TRSCSSV. This was done on two of the Kristin wells, and the wells experienced leakage through these valves. Scale is predicted in Morvin wells due to the $CaCO_3$ content of the produced water when water breakthrough has been reached. The solution to the problem has been downhole scale squeeze from intervention vessel once a year after water breakthrough.

Erosion and corrosion

Chemicals injected into the well or fluids that are produced can have a large effect on the wear and tear of the equipment. If the produced fluids has a high content of the sour gases hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) there will most likely have a severe consequence for the materials in the well. The high pressure and temperature of a HPHT well only require a small amount of sour gas for the environment to be highly corrosive. Morvin is expected to have a H_2S content between 12-15 ppm, and because of the high pressure, this is enough to bring the well into the sight sour service region which is require corrosion resistant alloys.

The load scenarios that have been calculated in Wellcat™ have been based on early life production. At an early stage in the lifetime of the well, pipes and equipment has not been exposed to erosive environments for long, which means that maximum erosion has not taken place. At the end of the lifetime of the well, the corrosion and erosion of the pipes may have increased to the point that failure will happen when certain well operations are executed. This scenario has to be evaluated when designing the well in terms of material selection, sand control, etc. The area under the production packer will not likely be affected by the long-term production because this area is shielded and once the area has been filled with fluid the displacement of fluid will be very slow.

Hydrates

At the start of the lifetime of this well it has been assumed no water production, but eventually the well will experience water break through. Hydrate formation may occur in environments with high pressure and low temperature. In the case of a high pressure/high temperature well, there is limited chance of hydrate formation during production. In the case of a long shut in period the temperature in the well may have dropped sufficiently so that hydrated can form. The chemical composition of the produced fluids has to be evaluated to determine when hydrate formation can be expected, and procedures for hydrate prevention shall be established.

Annulus bleed system

The annulus shall always be filled with a fluid if possible, and the annulus master valve and the ASCSV shall be open at all times. The annulus pressure shall be monitored to comply with the shut in wellhead pressure, incidents where this is not the case shall be investigated further.

A.9 Stimulation Fluids

Some wells require stimulation to keep up the productivity. For a HPHT well the stimulation can be left until the wellhead pressure is reduced to a more manageable pressure due to the depletion of the reservoir. This may lead to an uneven fracture distribution due to differential depletion. Consequences of this can be prevention of fracture growth into sealing formation (good), or prevent fracture growth into undepleted zones (bad) [Bellarby, 2009]. For the simulations for this thesis the well has been stimulated based on early life production, so the reservoir pressure has not been reduced from start up pressure. This will give a more extreme load scenario.

There are several stimulation fluids developed and adjusted to fit the specifications of different wells. It is important to select a fluid that can candle the extreme temperatures in a HPHT well, so that its chemical properties do not alter.

Crosslinked Gel Fluids

A common fluid used for stimulation is a cross-linked fluid. This is a type of gel that is good for proppant transport, has a stable rheology up to 148 °C, low fluid properties and good clean up properties [Halliburton 2012 B]. The crosslinked fluid utilize borate ions that interlock with hydrated polymers (Fig.- 9-10), and that will increase the viscosity of the fluid. Changing the pH of the well can reverse the crosslinking, this makes the clean up more effective, which result in a good regained productivity.

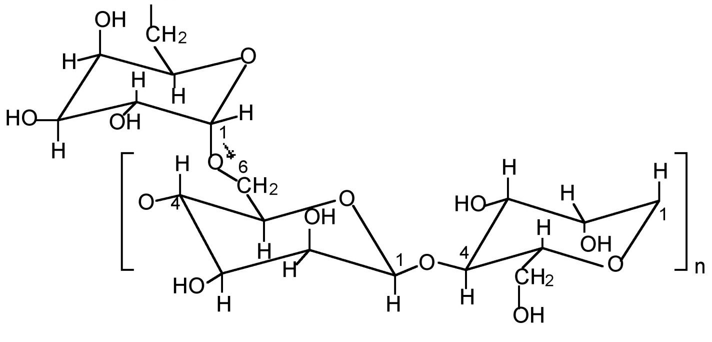


Fig.- 9-10 Boric acid cross-linking of guar gum for hydraulic fracturing fluids [Barron 2011].

For this case the well has been treated with seawater by bullheading so the temperature of the well has already been reduced before injection of the crosslinked fluid. This means that the temperature seen by the fracture fluid is less that 148 °C.

Crosslinked Organometallic Fluids

The most popular fractioning fluid type is crosslinked organometallic fluid. This type provides an extreme stability up to 204 °C and provides a better control of the crosslinking properties. It is commonly used for tight gas sand where long fracture length is required. Most used fluids are zirconate and titanate complexes of guar, hydroxpropyl guar and carboxymethyl- hydroxypropyl guar. [Halliburton 2012 B]

Gelled Oil Fluids

By using this type of fracturing fluids the formation damage can be minimized in certain formations like particle migration from water containing clays. The fluid is compatible with most type of rock formations and is very convenient in cold conditions. With no need for pre-mixing of the fluid it rapidly develop a consistent gel viscosity, which can easily be controlled while the treatment is being pumped. [Halliburton 2012 B]

Liquid Gel Concentrates

This type of fracturing fluid is a type of slurry with concentrated polymers in a liquid form that eliminate handling and mixing of dry powder at the rig. By adding LGC to an already hydrated gel the viscosity can easily be changed, or it can be added to water and pre-mixed to control viscosity while pumping. [Halliburton 2012 B]

Foamed Fluids

Foamed fracturing fluids usually contain a liquid gel, a foaming agent and a gas (typically 60-80 % of N_2 or CO_2). The gas in the foaming agent helps fluid recovery after fracturing. The foam can be widely used in all types of formations and pressures, and are often used where minimizing formation damage is important. Because of the low liquid content of the foam, there will be less fluid to remove from the well after stimulation. The gel in the foam can also be crosslinked to increase the viscosity. [Halliburton 2012 B]