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Author: Stian Bærheim	…………………………………………… (signature author)

Instructor: Erik Skaugen, UIS

Supervisor: Nina Furuløkken, StatoilHydro ASA

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Use of Expandable Pipe Technology to Improve Well Completions

Master Thesis

Petroleum Technology

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Stian Bærheim

Preface

The background for this thesis is well construction challenges in the Snorre field. It is sometimes necessary to drill two sections through the reservoir for reasons such as the length of the reservoir section, and the heterogeneity of the reservoir with some depleted zones. In addition, intelligent well completion systems are used in these wells, and these systems require a certain minimum diameter.

There are probably several different solutions to this challenge, but in order to limit the scope, this thesis is limited to expandable pipe technology. The reason for choosing this topic is that it seems like a promising technology for the type of well construction challenges seen in an increasing number of reservoirs, exemplified by the Snorre field.

The thesis first presents an introduction to the Snorre field. A theory section is then included with definitions and basic principles that are relevant in this thesis. An introduction to rock mechanics and a brief review of intelligent well systems and methods for zonal isolation are also included in the theory section. A section on expandable technology is then presented where some theory and calculations are included. Then, a case study is included where some relevant case histories are presented to illustrate some possible solutions, and a casing design with one type of solution is done with expandable liners from two different suppliers. A discussion is included to highlight some of the issues regarding expandable technology and the utilisation of this technology in this case.

I would like to thank the Snorre B team for giving me an interesting topic for my master thesis and particularly Nina Furuløkken for her help during the work on this thesis. I would also like to thank Frode Berge for technical input on expandable technology. In addition, I would like to thank André I. Røsbak for valuable feedback.

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Abstract

The underlying concept of expandable technology is cold-working a pipe downhole to the required size. An expansion cone is typically used to permanently deform the pipe downhole. The cone is pulled or pushed through the pipe hydraulically or by mechanical force. The cone introduces a stress to the pipe material above the yield stress and thereby plastically deforms the pipe while keeping the stresses below the ultimate yield.

Expandable technology gives the possibility of having more casing points in a well with little or no reduction in inner diameter. It may also increase the productivity of a well by increasing the sizes downhole, thus reducing the frictional pressure drop of the flowing fluids in the production tubing. In addition, expandable technology may give large environmental and economical benefits, such as development of smaller fields and deeper reservoirs, faster drilling speed, and reduced drilling fluids volume, cement volume, and amount of cuttings for disposal.

The pipe properties are affected by the expansion process. The cold-working process, in which the pipe is expanded, increases the yield strength of the material. The increase in yield strength may increase the burst pressure, depending on the expansion ratio and the wall thickness reduction. However, the collapse pressure may be significantly reduced because the D/t ratio is increased in the expansion process. The reduced collapse pressure may limit the range of application of expandable technology.

The expandable liners are not, at present, qualified as barriers or to be exposed to well fluids. When used in the reservoir, an expandable liner can be used as a drilling liner, which means that the liner is covered by another liner that acts as a production liner. The expandable liner does not need to be strong enough to handle production loads, only drilling loads. The expandable liners were in this case strong enough to handle most burst and collapse loads. However, they were not strong enough in collapse to handle the worst case scenario, which in this case was lost circulation with mud drop. If lost circulation zones are encountered the expandable liner may collapse. This represents only one example, for other wells the loads need to be determined for the specific case in which expandable liners are to be used.

Table of Contents

List of Figures

List of Tables

1 Introduction

1.1 The Snorre Field

The Snorre field is operated by StatoilHydro ASA and is located in block 34/4 and 34/7 of the Norwegian sector of the North Sea, approximately 150 km north-west of Bergen. The blocks were awarded in 1979 and 1984.

The Snorre field was discovered in 1979 and it covers an area approximately 8 km wide and 20 km long north of the Statfjord field and the Gullfaks field in the Tampen area of the North Sea. The plan for development and operation (PDO) was submitted in 1987 and it was approved in 1988. The development of the field was planned to be done in two phases: (1) the southern part was developed with a tension leg platform (TLP) supplemented by a subsea production system (SPS) tied back to the TLP, and (2) the northern part which is a subsea development tied back to a semi-submersible drilling, process and accommodation platform (Snorre B).

The production started in 1992 from Snorre A (TLP) in the southern part of the field from the Statfjord formation, and in 1993 from the Lunde formation via the SPS. The oil is transported by pipeline to Statfjord A, which handles further processing. The gas is exported through the Statpipe transportation system. Snorre B, which is used in the development of the northern part of the Snorre field, came on stream in 2001. The oil from Snorre B is transported by pipeline to the Statfjord B platform and the gas not used for injection is transported to Snorre A.

1.2 Reservoir Description and Draining Strategy

The Snorre reservoir consists of the Lunde formation and the Statfjord formation. Reservoir rocks of the Snorre field consist of coastal plain sandstones of the Statfjord formation and alluvial plain sandstones of the upper Lunde formation. The Snorre reservoir is a sandstone reservoir and it is located at 2300 to 2700 mTVD. The initial reservoir pressure was 383 bar at 2475 mTVD from MSL, and the reservoir temperature is 90 °C. The reservoir is highly faulted and complex, and is divided into 11 main zones. The main zones are subdivided into a total of 44 subzones. The main reservoir zone barriers are often pressure barriers, and this makes the reservoir very compartmentalised.

The drainage strategy for this field, with its complex reservoir geology and the resulting heterogeneity in reservoir properties, is based on long horizontal producers with commingled production from several reservoir zones. The main challenge with the draining of the reservoir is the difference in permeability in the reservoir zones. This leads to rapid water and gas breakthrough and poor sweep efficiency. In addition, the reservoir has been divided into flow units because of the vertical communication barriers and the boundaries between the zones. These flow units have to be flooded separately to achieve optimum sweep efficiency. Smart wells with intelligent completion systems are used in the Snorre field to cope with these challenges. These intelligent completions can be beneficial in reservoirs with a complex drainage pattern, multiple layers with a large difference in permeabilities, and a high pressure differential (StatoilHydro, 2008, p. 182), such as in the Snorre reservoir.

The reservoir drainage strategy for the Snorre field includes injecting water and gas to displace the oil and to maintain the reservoir pressure. Water alternating gas (WAG) injection and foam assisted water alternating gas (FAWAG) injection is used in some of the injectors. Reduction of water production is also one of the focus areas for the draining of the reservoir; the production on Snorre A is currently limited by process water capacity. Intelligent completions are being used to selectively produce from or inject into the individual reservoir zones. This system can be used to shut off or choke zones that produce water.

The intelligent completion provides the ability to control inflow from the different reservoir zones as well as monitoring downhole parameters. The ability to control inflow and monitor the downhole conditions makes it possible to close or choke producing zones with high water cut without intervention, optimise the injection profile, and optimise production when the process capacity is limited. Zone control has been recognised as one of the major methods for increased oil recovery (IOR) on the Snorre field (StatoilHydro, 2008, pp. 222-223). A typical producer or injector on the Snorre field has three to five downhole electro-hydraulic sleeves with pressure and temperature sensors on both the tubing and annulus side of the sleeves. Having sensors on both sides allows measurement of reservoir pressure and temperature even when the sleeve is closed.

1.3 Drilling and Completing the Reservoir

Some of the zones are more depleted than others and this makes drilling through the reservoir a challenge. When a zone is depleted the fracture gradient decreases accordingly, and this leads to a narrower mud window; because of this, certain zones may have to be cased off before drilling can be continued. In addition, since very long horizontal sections are needed through the reservoir, there is a problem with assuring zonal isolation across the zones in the reservoir because it is difficult to achieve a good cement job. These issues make drilling and completing the wells on the Snorre field a challenge.

Because of the difficulties drilling through several of the reservoir zones, the reservoir may have to be drilled in two sections. A 9 5/8" production liner has been set at the cap rock above the reservoir. The reservoir section has then been drilled with an 8 ½" bit and a 7" liner has been set. As a contingency, a second reservoir section can be drilled with a 6" bit followed by a 5 ½" or 4 ½" liner. The contingency solution can be used if for instance reservoir conditions make it necessary to case off a zone before drilling can be continued. It has also been used to increase the probability of getting a good cement job in the reservoir. If simulations show that it will be difficult or near impossible to cement the entire interval, the reservoir section can be split in two by using the contingency liner. The contingency solution has several disadvantages, one being that the small dimensions in the last reservoir section does not allow for intelligent completions since the inner diameter in the contingency liner is too small for the interval control valves (ICV).

A possible solution to this problem is the use of expandable technology. If the expandable liner system is included as part of the initial casing design it enables longer exploration wells and production wells with larger hole sizes at the reservoir. The system can also be used as a contingency plan which enables one to isolate zones that contain reactive shales, low fracture gradient formations, or other drilling situations without having to reduce the casing size and consequently the hole size into the reservoir (Stockmeyer, Tillman, Weirich, & Sehnal, 2006). There are several suppliers and different methods of setting expandables. To date, there is only one monobore system that has been installed commercially. If this monobore technology is used, a recess shoe is run at the end of the base casing/liner. The commercial installation was from a 9 5/8" base casing. The next hole section is then drilled and underreamed to a larger hole dimension to allow for expansion and possibly cementing of the next liner. The hole is underreamed to for instance 12 ½”, which is a standard bit size and it should also give a large enough annular clearance for cementing. If cementing is not required a smaller hole may be drilled. The expandable liner can then be run and expanded to an inner diameter corresponding to a 9 5/8” liner or casing. With this option it is possible to drill the last section of the reservoir with 8 ½” bit and set a 7” liner. Another option is to run an expandable liner from the 7” liner. The next hole section is then drilled and underreamed to a larger hole dimension. The next liner can then be run and expanded in the last section of the reservoir. Both of these options gives a larger inner diameter in the reservoir and may enable the use of an intelligent well system if zonal isolation can be achieved.

The downside of the expandable technology is that the collapse strength of the liner is reduced significantly after expansion, and for the time being, there are no solid expandable liners that are qualified as barrier elements or to be exposed to well fluids. There are several scenarios where collapse strength is needed. High collapse strength may be needed when cementing the liner; the differential pressure may be quite high during cementing when the annulus is filled with cement. Another scenario may be that the pore pressure is high if there are some zones that are not depleted; this pressure will try to collapse the pipe. Also, if low pressure zones are encountered during drilling, the drilling fluid level may drop to balance the formation pressure. This may cause the internal pressure to drop, and one risks collapsing the pipe.

2 Theory

2.1 General Theory

2.1.1 Stress and Strain

The stress in a material is an expression for the load state that the material is subjected to. The unit for stress is the same as for pressure. If a force F, is acting on a surface area A, the stress σ, is defined as:

$$\sigma = \frac{F}{A} \qquad \text{(Eq. 2.1)}$$

More generally, the body, on which the force acts, can be divided into an infinite number of subsections with surface ΔA_i. The force acting on this area is correspondingly ΔF_i. The stress at a point may then be defined as the limit when the area approaches zero (Fjær, Holt, Horsrud, Raaen, & Risnes, 2008, pp. 1-3):

$$\sigma = \lim_{\Delta A_i \to 0} \frac{\Delta F_i}{\Delta A_i} \qquad \text{(Eq. 2.2)}$$

The force component acting normal to the surface area gives the normal stress component, denoted by σ. The force component acting parallel to the surface area gives the shear stress, τ. There are two definitions of stress: true stress and engineering stress. The true stress is calculated from the actual (instantaneous) area, while the engineering stress uses the original area.

When a material is subjected to stress it becomes deformed, and the strain is an expression of this deformation. The strain is equal to the relative elongation of the material. As with stress, there are two definitions of strain: true strain $\varepsilon_t = \Delta L/L$, and engineering strain $\varepsilon_e = \Delta L/L_0$. The true strain is equal to the elongation ΔL divided by the actual length L, while the engineering strain is equal to the elongation ΔL divided by the original length L_0. The engineering strain may be the most practical to use since the original length is known, but the actual (instantaneous) length may not be known. The difference between true strain and engineering strain is small provided that the elongation is small (Boresi & Schmidt, 2003, p. 9).

In general, when a stress is applied to a material below a certain limit the material is not permanently deformed. This limit is called the yield limit, denoted by σ_Y in Figure 2-1, and the region below the yield limit in a stress-strain diagram is called the elastic region. Elastic behaviour means that the material will go back to its initial shape after deformation. When the stress exceeds the yield limit, the stress state goes into the plastic range and the material is permanently deformed. This means that the material will not go back to its initial shape, but maintain some of the deformation produced by the applied stress. The maximum engineering stress on this curve is called the ultimate tensile strength σ_u. If the material develops a local decrease in cross-sectional area, called necking, the engineering stress will decrease with further strain, since it is calculated from the original cross-sectional area. This means that for strains larger than the strain at σ_u, the engineering stress decreases until the material ultimately fails; however, the true strain in the material may increase since it is calculated based on the actual cross-sectional area.

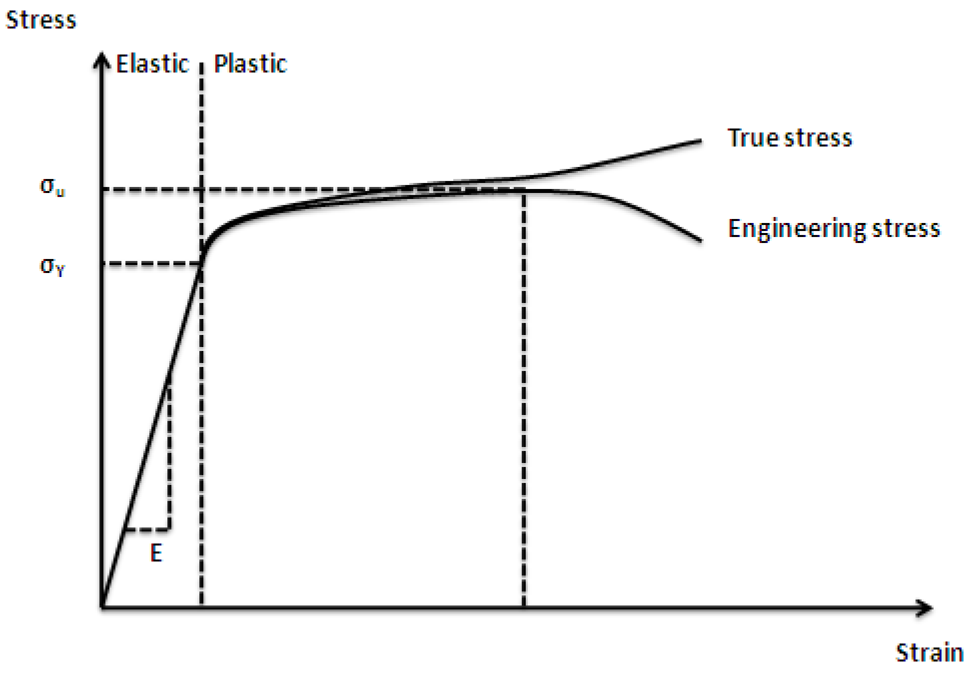

Figure 2-1 Stress-strain diagram

2.1.2 Modulus of Elasticity

The modulus of elasticity E, also called Young's modulus, is a measure of the material's stiffness, i.e. the material's resistance towards deformation. The modulus of elasticity is the slope of the straight line in the elastic region in a stress-strain diagram as indicated in Figure 2-1. Typical values for some relevant materials are given in Table 2-1.

Material	Young's modulus, E (GPa)
Sandstone	0.1-30
Shale	0.4-70
High porosity chalk	0.5-5
Low porosity chalk	5-30
Steel	200

Table 2-1 Typical values for Young's modulus for some relevant materials (Fjær et al., 2008, p. 437)

If a force F is applied to the ends of a sample of length L and cross-sectional area A, a stress σ is produced equal to the force divided by the cross-sectional area. The stress will result in a strain ε. The modulus of elasticity can be calculated based on the stress and the strain from Hooke's law in the elastic linear region:

$$E = \frac{\sigma}{\varepsilon} \qquad \text{(Eq. 2.3)}$$

2.1.3 Poisson's Ratio

The Poisson's ratio is a measure of the lateral expansion relative to longitudinal contraction. It is a dimensionless number and can be found by measuring the axial strain ε_x, and the lateral strain ε_y, in a uniaxial tension test, where the applied stress is in the x-direction. Poisson's ratio ν is given by

$$\nu = -\frac{\varepsilon_y}{\varepsilon_x} \qquad \text{(Eq. 2.4)}$$

Typical values for some relevant materials are given in Table 2-2.

Material	Poisson's ratio
Sandstone	0-0.45
Shale	0-0.30
High porosity chalk	0.05-0.35
Low porosity chalk	0.05-0.30
Steel	0.28

Table 2-2 Typical values for Poisson's ratio for some relevant materials (Fjær et al., 2008, p. 437)

2.1.4 Ductility

Ductility is the ability of a material to deform easily when a force is applied, or to withstand plastic deformation without rupture. Ductile materials can be deformed more before fracture than brittle materials. The ductility of a material is dependent on several factors, one being temperature. An increase in temperature increases the ductility, while a decrease in temperature decreases the ductility. Work hardening tends to make metals less ductile (Smith, 1993, pp. 227-228). The more ductile the material is, the more it will neck before fracture. This means that the engineering stress, which is calculated based on the original cross-sectional area, on the stress-strain curve (Figure 2-1) decreases considerably beyond the maximum stress before rupture (Smith, 1993, pp. 205-207).

The amount of elongation in a tensile test can be used as a measure for the ductility of the material. The final length and the initial length are measured and percent elongation can be calculated. The reduction in cross-sectional area can also be used as a measure for the ductility of the material. The initial area and the area after the tensile test is then measured, and percent reduction in area can be calculated from these measurements. The higher the elongation and area reduction, the more ductile the material is.

2.1.5 Toughness

The toughness describes the way the material reacts under sudden impacts. The modulus of toughness is a measure of the material's ability to absorb energy before it fractures, and it represents the strain energy per unit volume, which is the strain-energy density, in the material at fracture. The strain-energy density is equal to the area under the stress-strain curve from zero to the point of fracture. The larger the modulus of toughness is, the larger the material's ability to absorb energy without fracturing will be (Boresi & Schmidt, 2003, p. 13).

2.1.6 Hardness

The hardness of a material is the ability to resist plastic deformation, penetration, indentation and scratching. This property is important because the resistance to resist wear and erosion increases with the hardness.

The hardness is measured by forcing an indenter into the material's surface. The indenter is made of a material much harder than the material being tested. An empirical hardness number is determined based on the cross-sectional area or depth of the impression.

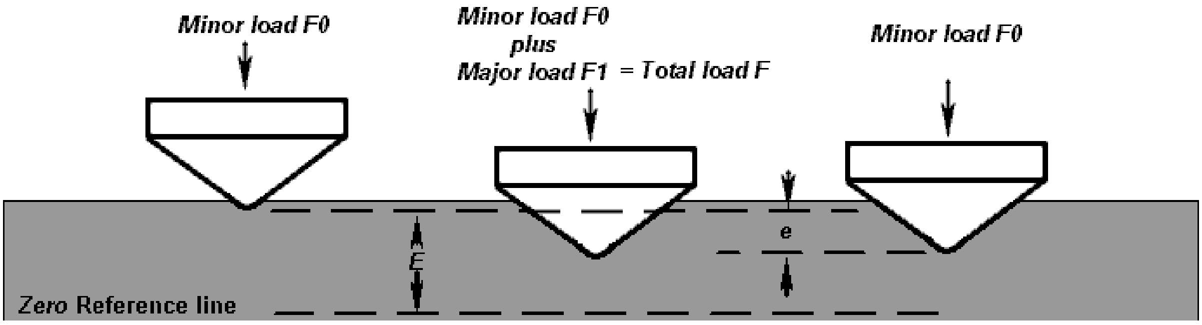

Figure 2-2 Rockwell hardness test (England, 2009)

One example of a hardness test is the Rockwell hardness test. The indenter used is either a diamond cone or a hardened steel ball indenter. The indenter is first forced into the test material with a certain load, called a minor load F0. When equilibrium is reached, the depth of penetration is measured and this depth is used as a datum position. A major load F1 is applied in addition to the minor load F0. When equilibrium has been reached, the major load is removed, while the minor load is maintained. The depth of penetration e is then measured relative to the datum, as illustrated in Figure 2-2. The hardness can then be calculated from

$$HR = E - e \qquad \text{(Eq. 2.5)}$$

where HR is the Rockwell hardness and E is a constant depending on the indenter: 100 for diamond cone, 130 for steel ball. Table 2-3 shows some of the values used for some of the Rockwell hardness scales.

Scale	Indenter	Minor load F0 [kg]	Major load F1 [kg]	Total load F [kg]	E
HRA	Diamond cone	10	50	60	100
HRB	1/16” steel ball	10	90	100	130
HRC	Diamond cone	10	140	150	100

Table 2-3 Rockwell hardness scales (England, 2009)

HRA is used for cemented carbides, thin steel and shallow case hardened steel. HRB is used for copper alloys, soft steels, aluminium alloys and other soft materials. HRC is used for steel, hard cast irons, case hardened steel and other materials harder than 100 HRB (England, 2009).

A relationship between the hardness and the strength can be determined empirically. The hardness test is non-destructive and can be performed to get an indication of the strength of the material instead of doing a tensile test which destroys the specimen being tested (Smith, 1993, pp. 210-212).

2.1.7 Steel Structure and Treatments

Steel is an iron and carbon alloy, and the carbon content is less than approximately 2 % by weight. If the carbon content is higher than 2 %, the alloy is classified as cast iron.

Iron may exist in different crystal forms at a certain pressure, depending on the temperature, see Figure 2-3. At atmospheric pressure, iron exists as alpha iron, also called ferrite, up to 912 °C; gamma iron, called austenite, between 912 °C and 1394 °C; and delta iron, also called delta-ferrite, from 1394 °C to 1538 °C which is the melting point of pure iron (Krauss, 1980, p. 4).

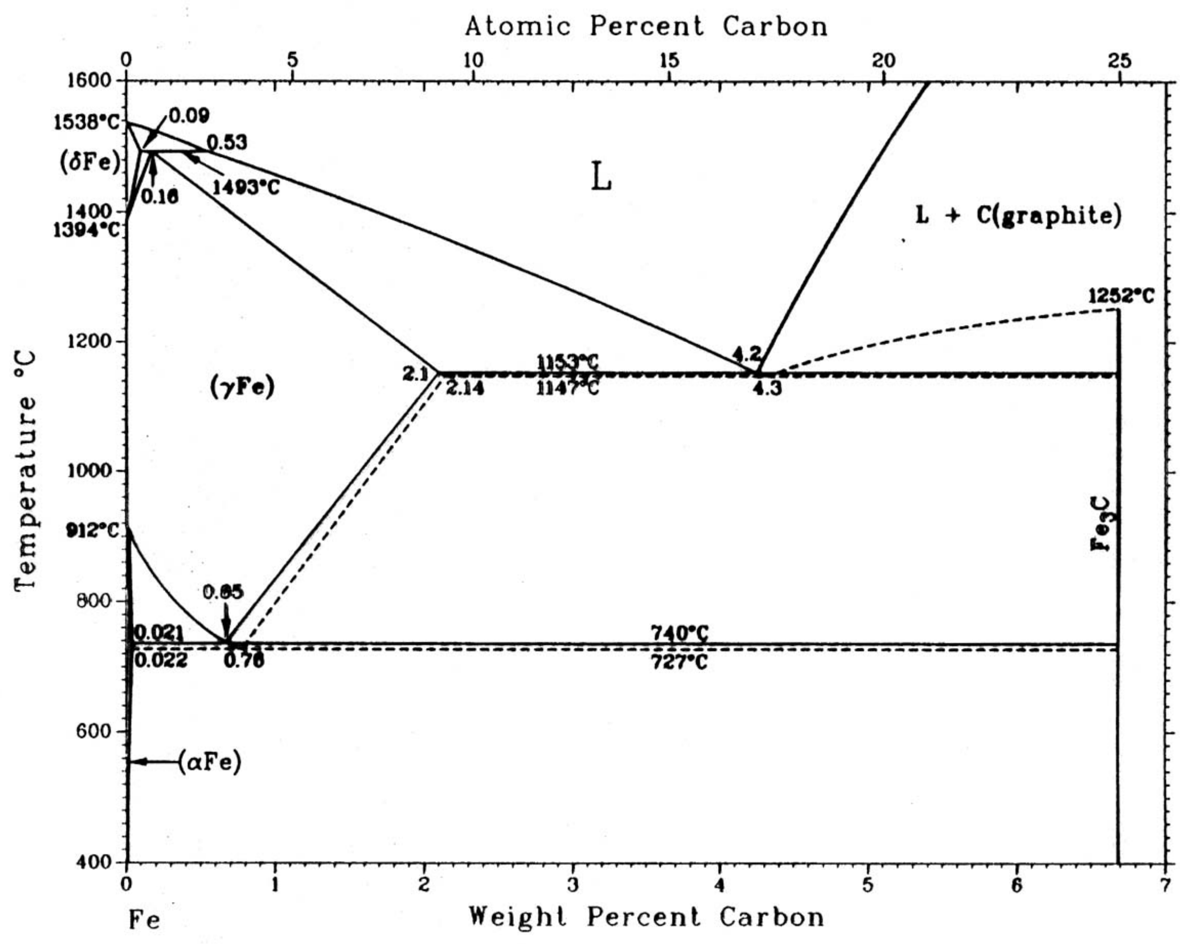

Figure 2-3 Iron-carbon phase diagram (Kramer, 1999)

The crystal forms in iron are referred to as having a body-centered cubic (bcc) crystal structure or a face-centered cubic (fcc) crystal structure, and these crystal structures are illustrated in Figure 2-4 and Figure 2-5, respectively. Ferrite in steel is bcc and austenite in steel is fcc. The ferrite crystal form (bcc) is a smaller, but less dense structure than the austenite crystal form (fcc). This difference in crystal structure causes a volume expansion when the higher density austenite transforms to ferrite during cooling.

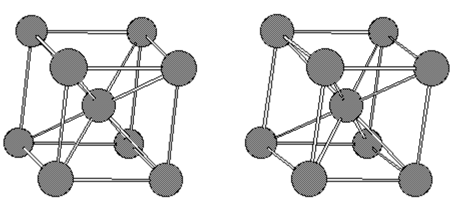

Figure 2-4 Body-centered cubic (bcc) crystal structure (Watkins, 2009)

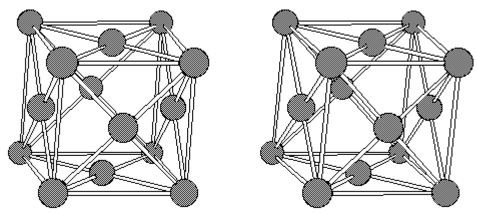

Figure 2-5 Face-centered cubic crystal structure (Watkins, 2009)

When carbon is added to iron, the phase equilibrium lines in the phase diagram changes. The carbon atom goes into the interstices in the crystal structure. Carbon stabilizes austenite and increases the range in which austenite can form in steel. The maximum carbon solubility in austenite is 2.11 % at 1148 °C. The solubility of carbon in ferrite is much less and the maximum solubility is only 0.02 % and occurs at 727 °C. The carbon content affects the mechanical properties of the steel. The toughness decreases drastically with increasing carbon content. Steel with high carbon content has very low toughness, but high hardness and wear resistance (Krauss, 1980, p. 188).

The solidification of a metal or alloy basically consists of three steps: (1) formation of a stable nuclei, (2) growth of nuclei into crystals, and (3) joining together crystals to form a grain structure (Smith, 1993, pp. 121-122). Most solidified metals contain many crystals and are called polycrystalline metals, but there also exist monocrystalline metals that are used in for instance solar cells. The crystals in a solidified metal are called grains and the surfaces between the crystals are called grain boundaries. The grain size is affected by cooling rate and whether grain refiners are used. Grain refiners are materials that can be added to the metal to alter the grain size (Smith, 1993, p. 128). If the metal is cooled rapidly in the solidification process, the crystal growth is limited and the metal produced is fine grained. The faster a metal is cooled, the smaller the grain sizes will be. A small grain size makes the metal hard, however, the toughness and ductility decreases as hardness increases. By varying the cooling rate, different properties can be produced.

Usually, all steels that are hardened are subjected to a heat treatment below the critical temperature. This process is referred to as tempering. Tempering improves the toughness, but lowers strength and hardness (Krauss, 1980, p. 187).

Hardened steel may be quite brittle. Tempering is then performed to reduce brittleness or increase toughness. Any subcritical temperature, i.e. a lower temperature than the transformation temperatures shown in Figure 2-3, can be used, thus a wide variation in properties can be produced by tempering. The balance of hardness or strength and toughness required in the specific application determines the tempering conditions. For example, for hardened 0.4 % carbon steel, there are two important temperature ranges where tempering produces significant improvement in toughness (Krauss, 1980, pp. 187-189). The impact toughness as a function of tempering temperature is shown in Figure 2-6.

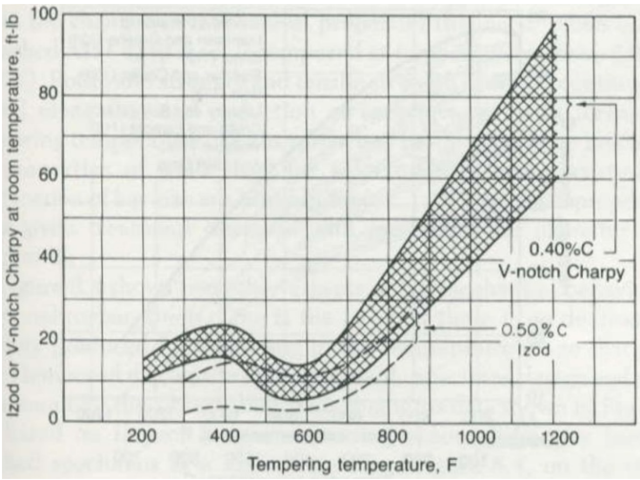

Figure 2-6 Impact toughness as a function of tempering temperature of hardened steel

Using a temperature range of 150 °C to 200 °C produces a small increase in toughness. Tempering in this range can be used for carbon steel in applications that require high strength and hardness, and the increased toughness that the tempering process provides. Another important temperature range is temperatures above approximately 425 °C. The toughness increases significantly if tempering is done above this temperature, however, hardness and strength also decreases correspondingly.

Tempering in this range is therefore used where high toughness is needed, and where strength and hardness are not critical properties. There are temperature ranges where the toughness actually decreases; in this case this is approximately 260 °C to 370 °C (Krauss, 1980, p. 188).

Other mechanical properties of steel are also affected by the tempering process. Yield strength and tensile strength decrease, and elongation and reduction of area increase with increasing tempering temperature (Krauss, 1980, pp. 190-193).

Other elements can be introduced to the steel structure to alter the properties. Elements such as manganese, molybdenum, chrome, nickel and copper can be used to give the material the desired properties.

2.1.8 Work Hardening

Polycrystalline metals are composed of a large number of very small units called crystals or grains. These crystals have slip planes on which the resistance to shear stress is relatively small. Under elastic loading, the crystal itself is distorted because of stretching or compressing the atomic bonds. The crystal returns to its undistorted state if the load is removed and there is no permanent deformation. If a load above the yield strength is reached below the recrystallisation temperature, the crystals are distorted as before, and in addition, defects in the crystals move in the slip planes. These defects are known as dislocations. When the dislocations move in the slip planes, atomic bonds break. When the load is removed the distorted crystals are recovered, but the movement of the dislocations does not. The result is a permanent deformation (Boresi & Schmidt, 2003, p. 21).

After the crystals have yielded sufficiently, these crystals will not yield further without an increase in the load. The reason is that the dislocation density increases and the dislocations entangles, thereby making motion of dislocations more difficult. The result is that a higher stress is needed to push new dislocations through the entanglements. This increase in resistance to deformation that is developed after yielding is known as work hardening or strain hardening. While work hardening increases hardness and tensile strength, it lowers the ductility of the material (Smith, 1993, pp. 227-228).

2.1.9 Bauschinger Effect

The Bauschinger effect can be explained by considering a specimen loaded in tension in the inelastic range. The tension load is then gradually removed and then the specimen is loaded in compression. In an ideal model, the compressive yield should be equal to the initial yield stress. However, it has been observed that the compressive loading following a tensile unloading from the inelastic region results in a decrease in compressive yield stress (Boresi & Schmidt, 2003, p. 106).

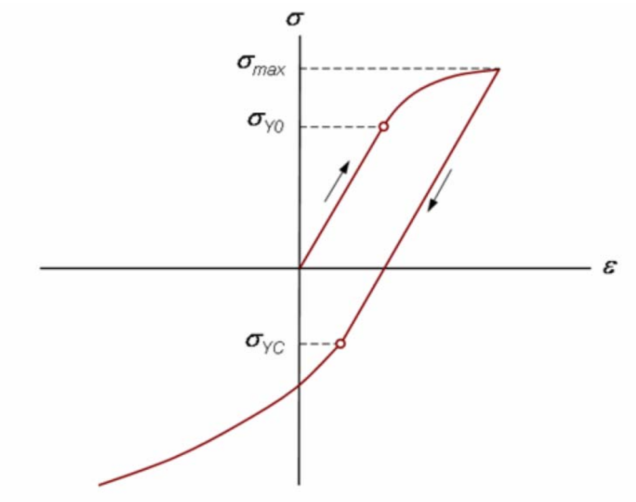

Figure 2-7 Bauschinger effect (Ruan & Maurer, 2005)

The Bauschinger effect is illustrated in Figure 2-7, where σ_{max} is the maximum stress the material is loaded to in tension, σ_{Y0} is the initial yield stress, and σ_{YC} is the compressive yield stress after the material has been loaded to σ_{max} in tension. The figure shows that the compressive yield stress is smaller after the material has been loaded above the yield stress in tension; however, this phenomenon is usually symmetric. If the material had been loaded in compression above the yield stress and then loaded in tension, the tensional yield stress would have been reduced.

2.1.10 Autofrettage

Cylinders made of a ductile material can be strengthened by introducing residual stress distributions that are beneficial. Beneficial stress distributions can be produced by subjecting for instance a cylinder to a high internal pressure, which leads to yielding and inelastic deformations in the cylinder. The beneficial residual stress distributions remain in the cylinder after the pressure has been removed, and this increases the load-carrying capacity. The residual stress distribution depends on the depth of yielding produced by the internal pressure, the shape of the stress-strain diagram for the material, and the shape of the stress-strain diagram for tensile unloading followed by compression loading (Boresi & Schmidt, 2003, p. 405). If the material is elastic-perfectly plastic, all the increase in load-carrying capacity is because of the beneficial residual stress distribution. However, if the material is a strain-hardening material, a part of the increase in load-carrying capacity is due to strengthening of the material from strain hardening the material.

The process of increasing the strength of a cylinder by applying high internal pressure until inelastic deformation to produce a beneficial residual stress distribution is called autofrettage.

The beneficial effect of the autofrettage process increases as the inelastic deformation spread through the wall of the cylinder. The inelastic deformation starts at the inner wall and spreads outwards. After the entire wall thickness has been yielded, any further increase in load-carrying capacity resulting from additional inelastic deformation is because of strain hardening (Boresi & Schmidt, 2003, p. 405).

2.1.11 Burst

Two critical properties for pipes that are run into a well are the burst and collapse resistances. The differential pressures downhole can be very high and it is important to know the load properties of the pipes downhole.

The burst pressure of a pipe is the pressure at which the pipe loses its internal pressure integrity. API calls this failure ductile rupture. The API equations for ductile rupture are for calculating the pressure at which failure of the pipe body occurs, not until the material yields.

The equations for ductile rupture depend on the following parameters:

- minimum physical wall thickness,
- pipe outer diameter,
- maximum depth of imperfections which have a reasonable probability of passing through the inspection process undetected,
- fracture toughness of the material,
- work hardening of the material, and
- ultimate tensile strength of the pipe.

The equations have been derived under two assumptions: (1) the failure of the pipe is assumed to be ductile and not brittle, even in the presence of small imperfections; and (2) bending stresses are not included, which means that the equations cannot be used for a buckled pipe or a pipe in a dogleg.

The design equation for ductile rupture as defined by API is as follows (American Petroleum Institute, 2008, p. 24):

$$p_{iR} = \frac{2k_{dr} f_{umn} (k_{wall} t - k_a a_N)}{D - (k_{wall} t - k_a a_N)} \qquad \text{(Eq. 2.6)}$$

where

a_N is the imperfection depth associated with a specified inspection threshold;

D is the specified pipe outside diameter;

f_{umn} is the specified minimum tensile strength;

k_a is the burst strength factor, usually having the numerical value 1.0 or 2.0 depending on the material;

k_{dr} is the correction factor based on pipe deformation and material strain hardening, having the numerical value $[(1/2)^{n+1} + (1/\sqrt{3})^{n+1}]$;

k_{wall} is the factor to account for the specified manufacturing tolerance of the pipe wall;

n is the dimensionless hardening index used to obtain a curve fit of the true stress-strain curve derived from the uniaxial tensile test;

p_{iR} is the internal pressure at ductile rupture of an end-capped pipe;

t is the specified pipe wall thickness.

2.1.12 Collapse

The API collapse design equation is used when the external fluid pressure exceeds the internal fluid pressure. The collapse equation does not account for bending.

The collapse equations depend on the following parameters:

- pipe outside diameter D,
- minimum yield strength f_{ymn},
- elastic modulus E, and
- pipe wall thickness t.

The calculation of the collapse pressure of a pipe is a bit more complex than the calculation of the burst pressure. There are basically three different failure modes for the collapse of pipes. These modes are elastic, plastic and yield. The formulas for elastic and yield collapse were determined analytically, the formula for plastic collapse was derived empirically. The diameter to thickness ratio and the yield stress of the material dictates in which mode the pipe fails in collapse. For high D/t ratios, i.e. thin-walled pipes, the failure mode is elastic, which means that the stress in the pipe material does not exceed the material yield stress. For lower D/t ratios the failure mode in collapse is plastic, which means that the yield stress has been exceeded and the pipe has been plastically deformed. For the API formulas for calculation of collapse pressure, there is also an empirical equation for a transition range between the elastic region and the plastic region. For pipes with a very low D/t ratio, i.e. small diameter and thick-walled pipes, the failure mode is yield collapse. The collapse pressure calculated in this region is the external pressure that generates minimum yield stress on the inside wall, and it is calculated using the Lamé equation. The applicable D/t range and collapse pressure can be calculated using formulas given by API, and these are given in Table 2-4.

Failure mode	Applicable D/t range
1. Elastic $P_E = 0.7125 \dfrac{2E}{1-\nu^2} \dfrac{1}{(D/t)[(D/t)-1]^2}$	${}^{D}/_{t} \geq \dfrac{2+B_c/A_c}{3B_c/A_c}$
2. Transition $P_T = f_{ymn}\left[\dfrac{F_c}{D/t} - G_c\right]$	$\dfrac{f_{ymn}(A_c-F_c)}{C_c+f_{ymn}(B_c-G_c)} \leq {}^{D}/_{t} \leq \dfrac{2+B_c/A_c}{3B_c/A_c}$
3. Plastic $P_P = f_{ymn}\left[\dfrac{A_c}{D/t} - B_c\right] - C_c$	$\dfrac{\sqrt{(A_c-2)^2+8(B_c+C_c/f_{ymn})}+(A_c-2)}{2(B_c+{}^{C_c}/_{f_{ymn}})} \leq {}^{D}/_{t} \leq \dfrac{f_{ymn}(A_c-F_c)}{C_c+f_{ymn}(B_c-G_c)}$
4. Yield $P_{Yp} = 2f_{ymn}\dfrac{({}^{D}/_{t})-1}{({}^{D}/_{t})^2}$	${}^{D}/_{t} \leq \dfrac{\sqrt{(A_c-2)^2+8(B_c+C_c/f_{ymn})}+(A_c-2)}{2(B_c+{}^{C_c}/_{f_{ymn}})}$

Empirical constants in SI-units:

$$A_c = 2.8762 + 0.15489 \times 10^{-3} f_{ymn} + 0.44809 \times 10^{-6} {f_{ymn}}^2 - 0.16211 \times 10^{-9} {f_{ymn}}^3$$
$$B_c = 0.026233 + 0.73402 \times 10^{-4} f_{ymn}$$
$$C_c = -3.2125 + 0.030867 f_{ymn} - 0.15204 \times 10^{-5} {f_{ymn}}^2 + 0.77810 \times 10^{-9} {f_{ymn}}^3$$
$$F_c = \frac{3.237 \times 10^5 \left(\dfrac{3B_c/A_c}{2+B_c/A_c}\right)^3}{f_{ymn}\left(\dfrac{3B_c/A_c}{2+B_c/A_c} - B_c/A_c\right)\left(1 - \dfrac{3B_c/A_c}{2+B_c/A_c}\right)^2}$$
$$G_c = F_c B_c/A_c$$

Table 2-4 API formulas for collapse (American Petroleum Institute, 2008, pp. 30-38)

2.2 Rock Mechanics

2.2.1 Introduction

Underground formations that are drilled through are always in a stressed state because of overburden and tectonic stresses. When a well is drilled, stressed material is removed and the stress state near the borehole is disturbed. The fluid pressure in the borehole supports the borehole wall and it is important to know the upper and lower limits of the well pressure to avoid a failure at the borehole wall.

During drilling, the limits for the well pressure are the pore pressure, as the lower limit, and the fracturing pressure, as the upper limit. If the well pressure is lower than the pore pressure, reservoir fluid will flow into the well. This situation is called a kick, and this may lead to a blowout if it gets out of control. If the well pressure exceeds the fracturing pressure of the formation, mud is lost, i.e. lost circulation.

Cementing is another process in which it is important to stay below the fracturing pressure. If the pressure exerted by the cement column exceeds the fracturing pressure, the cement is lost to the formation and the cement job may fail to fulfil its objectives.

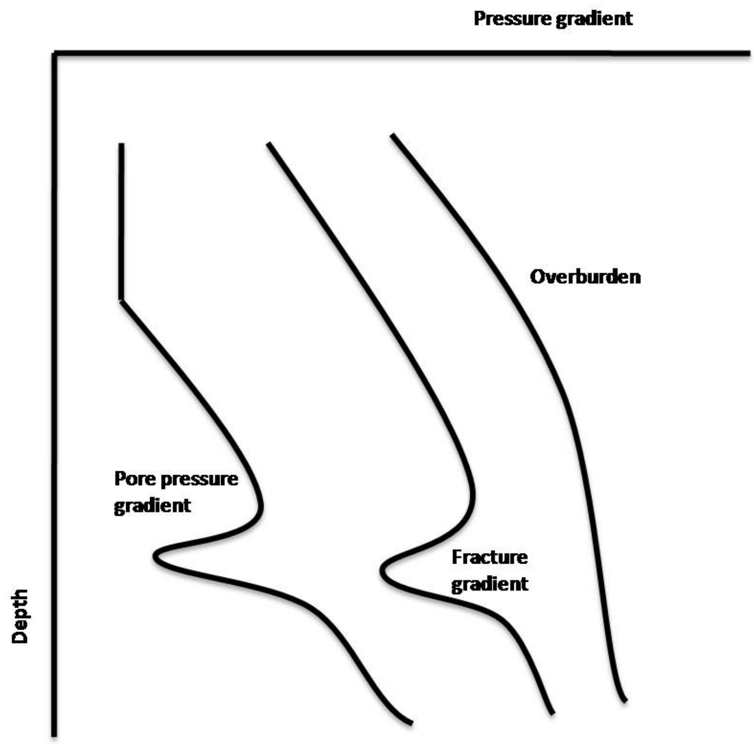

Figure 2-8 Illustration of pore pressure, fracturing pressure and overburden as a function of depth

Figure 2-8 shows the principle of pressure gradients that have to be considered when drilling a well. The area between the pore pressure gradient and the fracture gradient represents the mud window. The mud window can be quite narrow in partially depleted reservoirs.

Modern oil production often includes infill drilling as a method to increase oil or gas recovery after the reservoir has been produced for a while. Knowledge about the specific reservoir is then greater than it was before production started, and it is known where there are hydrocarbons left in the reservoir, which makes it possible to determine where more wells should be drilled to maximise the recovery. However, drilling in a depleted reservoir poses challenges, especially in heterogeneous reservoirs, where there may be multiple zones with pressure barriers between the zones. Some of these zones may have initial pore pressure and some may be depleted, thus giving a large variation in pore pressure. When drilling through these zones, the well pressure in the entire open section, i.e. from one casing shoe until the next casing is set, must be larger than the pore pressure and less than the fracturing pressure at any point. This may limit the length of the hole section before a casing needs to be set to isolate the formation.

2.2.2 Underground Stresses

An underground formation has to carry the weight of all the overlying formations, including the weight of sea water in offshore locations. If the overlying formations have a uniform density, the vertical stress, or overburden, is equal to $\sigma_V = \rho g z$, where ρ is the density of the overlying formations, g is the acceleration of gravity, and z is the vertical downwards distance from surface. In practice, however, the density varies and the vertical stress at true vertical depth TVD is equal to

$$\sigma_V = \int_0^{TVD} \rho(z) g dz \qquad \text{(Eq. 2.7)}$$

where 0 is at sea surface at offshore locations. The density ρ(z) represents the density of the overlying formation or the sea water at vertical downwards distance z.

The stress state in the underground formations consists of three orthogonal principal stresses, and in the oil industry it is usually assumed that the vertical stress is a principal stress (Fjær et al., 2008, p. 104). The vertical stress, in addition to other tectonic processes, also causes a horizontal stress, which in general is different from the vertical stress. In a formation there may be both a minimum horizontal stress σ_h, and a maximum horizontal stress σ_H, or the horizontal stresses may be equal.

There are several methods of calculating the in situ stress state in the formation. A simple model assumes that the formation is laterally constrained, i.e. no horizontal strain, and that the rock behaves linearly elastic. These assumptions may be used in Hooke's law for porous materials:

$$E\varepsilon_x = \sigma'_x - \nu(\sigma'_y + \sigma'_z) \qquad \text{(Eq. 2.8)}$$
$$E\varepsilon_y = \sigma'_y - \nu(\sigma'_x + \sigma'_z) \qquad \text{(Eq. 2.9)}$$
$$E\varepsilon_z = \sigma'_z - \nu(\sigma'_x + \sigma'_y) \qquad \text{(Eq. 2.10)}$$

where z is the vertical direction, and x and y are the horizontal directions. The parameters σ'_i (i = x, y, z) are the effective stresses, see equation 2.13.

Inserting the assumption that there is no horizontal strain ($\varepsilon_x = \varepsilon_y = 0$) in equation 2.8 or 2.9, an expression for the horizontal stress is obtained:

$$\sigma'_h = \frac{\nu}{1-\nu}\sigma'_V \qquad \text{(Eq. 2.11)}$$

where h represents the x- or y-direction, and V represent the z-direction.

2.2.3 Pore Pressure

Porous rocks contain fluids in the pores. The fluid pressure can be either normal or abnormal. If the fluid pressure is equal to the weight of a fluid column above, the fluid pressure is referred to as normal pressure and is then equal to

$$P_o = \int_0^{TVD} \rho_f(z) g dz \qquad \text{(Eq. 2.12)}$$

where P_o is the pore pressure and ρ_f is the density of the fluid in the pores. Note that it is the fluid pressure at the oil-water-contact or the gas-water-contact that should be equal to equation 2.12 for it to be considered normal pressure. The pressure at the top of the reservoir is in general higher than the normal pressure because oil and gas is less dense than water, which means that the pressure gradient above the water-contact is less than below the water-contact.

As sediments are buried, pore pressure will develop in a saturated formation. If the fluid can escape and migrate at the same rate as the compaction rate, a normal pore pressure gradient is maintained. The pore pressure in the formation is then given by equation 2.12.

There are several possible reasons for abnormal pressures, and usually the pore pressure is higher than normal pressure. Abnormal pore pressure, or overpressure, has three main causes (Fjær et al., 2008, p. 115):

1. The rate of sedimentation and compaction is higher than the rate of fluid migration.
2. Tectonic loading leads to undrained shear stress with associated pore pressure development.
3. Pore fluid expansion generated by thermal or chemical processes.

Compacted clays have very low permeability, thus shaly zones can easily become overpressured. It is difficult to estimate the permeability of shale because shale cores are altered when they are retrieved to surface. The laboratory measurements of the permeability are often overestimated; however, shale permeabilities are typically in the nanoDarcy range (Fjær et al., 2008, p. 115). The shale permeability is often low enough that a thick shale formation is not able to expel fluid at the same rate as it is compacted. Sands embedded in such shales are also likely to become overpressured. Rapid sedimentation is another possible reason for overpressured formations.

There is a strong correlation between overpressured formations and compressional tectonics (Fjær et al., 2008, p. 115). Pore pressure will increase or decrease with tectonic activity, depending on the stress state in the formation. Tectonic activity will only result in sustained abnormal pore pressure if the system is closed. If the system is open or fractured, pore fluid may escape over time, resulting in normal pore pressure.

Another reason for abnormal pore pressure is temperature change. An increase in temperature may lead to an expansion of the pore fluid, which causes the pore pressure to increase.

The pore pressure may also be slightly different from expected because of the salinity of the pore fluid. The salinity of the pore fluid is in general not constant and may increase with depth because the increasing temperature makes salt more soluble in water. The salinity of the pore fluid may also depend on the rocks that the water has been in contact with. If the salinity is not known, the fluid density cannot be accurately determined. Pore pressure encountered when drilling may then be different than expected. This is, however, normal pore pressure, but since the fluid composition is not known, the pressure is different from expected normal pore pressure.

The pore pressure is important in the study of stress states in porous rocks because the pore pressure will carry a part of the total stress and thereby relieve the matrix from a part of the load. The effective stress σ', which the grains are affected by, is equal to the total stress σ, minus the pore pressure, P_o:

$$\sigma' = \sigma - P_o \qquad \text{(Eq. 2.13)}$$

In conventional drilling operations, the drilling fluid used has a density such that the downhole pressure is higher than the pore pressure to avoid inflow of pore fluid into the well. If the well pressure gets lower than the pore pressure, which leads to inflow of pore fluid, the density of the drilling fluid in the well decreases due to the lower density of the pore fluid. A lower density will lead to an even lower downhole pressure and more inflow of pore fluid. This is called a well kick. The pore fluid needs to be circulated out with a drilling fluid with higher density to avoid further inflow before drilling can be continued.

2.2.4 Fracturing Pressure

When drilling through a formation it is important to have a well pressure below the fracturing pressure to avoid fracturing the formation. If this happens some or all of the drilling fluid is lost to the formation. If too much drilling fluid is lost the fluid level in the annulus decreases and lowers the downhole pressure. This may lead to well control situations such as kicks or blowouts, or if it happens when casing/liner is being run into the hole, it may collapse the pipe. Another situation where the fracturing pressure may be a problem is during cementing. During cementing the downhole pressure increases and this may fracture the formation. If the formation fractures, some or all of the cement is lost, and one does not achieve a good cement job. This can be critical in the reservoir sections, because the cement is part of the well barrier. It may also be a requirement that the reservoir sections should have zonal isolation, which is not achieved if the cement job fails.

When the reservoir gets depleted, which means that the pore pressure has decreased, the fracturing pressure also decreases. Since the pressure in the well needs to be between the pore pressure and the fracturing pressure at all times, the available mud window decreases, especially when there are several reservoir zones where some are depleted and some are not.

The procedure for determining the fracturing pressure is taken from Fjær et al. (2008, pp. 145-150, 154-157), and is explained below.

The in situ stresses defines a coordinate system which is denoted (x', y', z'). The overburden σ_V, is parallel to z', the maximum horizontal stress σ_H, is parallel to x', and the minimum horizontal stress σ_h, is parallel to y' as shown in the left part of Figure 2-9. A second coordinate system (x, y, z) is introduced such that the z-axis is parallel to the wellbore axis, the x-axis points towards the low side of the hole, and the y-axis is horizontal, as illustrated in the right part of Figure 2-9.

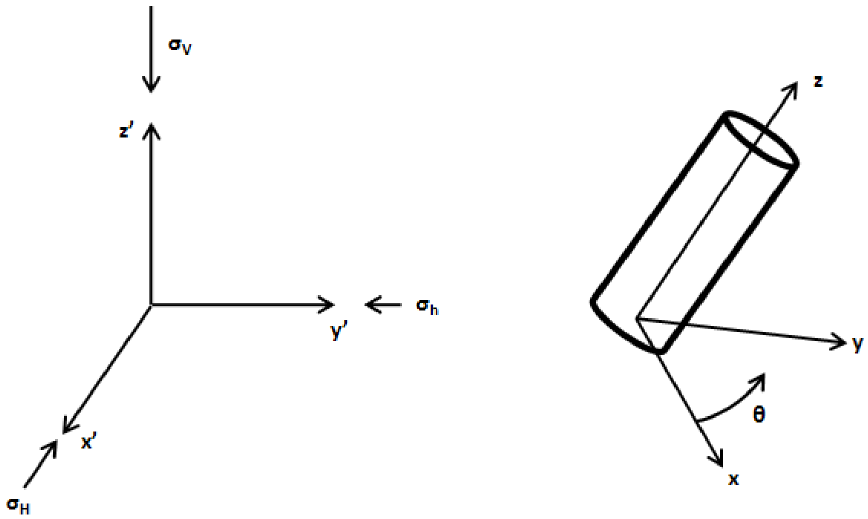

Figure 2-9 Coordinate system defined by the in situ principal stresses (Fjær et al., 2008, p. 146)

A coordinate transformation is done in two operations: (1) a rotation a around the z'-axis, measured counter-clockwise from the x'-axis to the x-axis; and (2) a rotation i around the y-axis, where i is the angle between the z'-axis and the z-axis. The transformation geometry is illustrated in Figure 2-10.

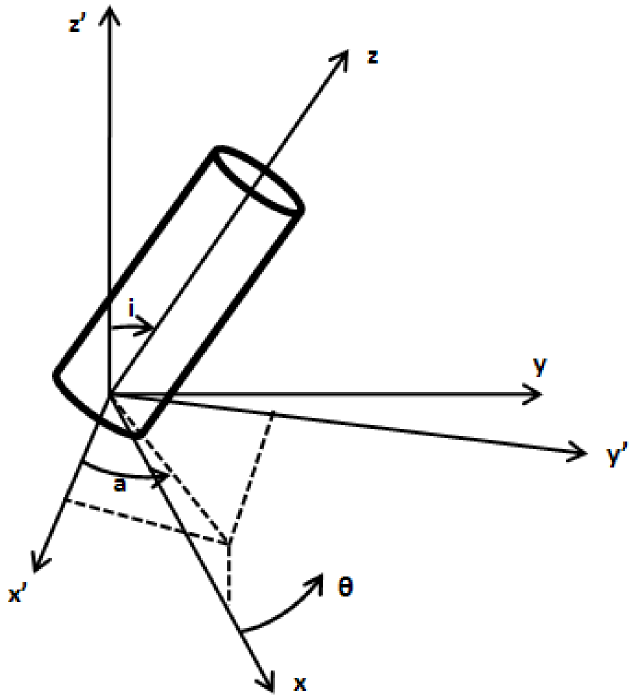

Figure 2-10 The transformation geometry (Fjær et al., 2008, p. 147)

The transformation can be calculated from the direction cosines:

$$
\begin{aligned}
&l_{xx'}=\cos(a)\cos(i), && l_{xy'}=\sin(a)\cos(i), && l_{xz'}=-\sin(i), \\
&l_{yx'}=-\sin(a), && l_{yy'}=\cos(a), && l_{yz'}=0, \\
&l_{zx'}=\cos(a)\sin(i), && l_{zy'}=\sin(a)\sin(i), && l_{zz'}=\cos(i)
\end{aligned}
\qquad \text{(Eq. 2.14)}
$$

The formation stresses σ_H, σ_h and σ_V in the (x, y, z) coordinate system become:

$$\sigma_x^0 = l_{xx'}^2\sigma_H + l_{xy'}^2\sigma_h + l_{xz'}^2\sigma_V \qquad \text{(Eq. 2.15)}$$
$$\sigma_y^0 = l_{yx'}^2\sigma_H + l_{yy'}^2\sigma_h + l_{yz'}^2\sigma_V \qquad \text{(Eq. 2.16)}$$
$$\sigma_z^0 = l_{zx'}^2\sigma_H + l_{zy'}^2\sigma_h + l_{zz'}^2\sigma_V \qquad \text{(Eq. 2.17)}$$
$$\tau_{xy}^0 = l_{xx'}l_{yx'}\sigma_H + l_{xy'}l_{yy'}\sigma_h + l_{xz'}l_{yz'}\sigma_V \qquad \text{(Eq. 2.18)}$$
$$\tau_{yz}^0 = l_{yx'}l_{zx'}\sigma_H + l_{yy'}l_{zy'}\sigma_h + l_{yz'}l_{zz'}\sigma_V \qquad \text{(Eq. 2.19)}$$
$$\tau_{zx}^0 = l_{zx'}l_{xx'}\sigma_H + l_{zy'}l_{xy'}\sigma_h + l_{zz'}l_{xz'}\sigma_V \qquad \text{(Eq. 2.20)}$$

The stresses at the borehole wall are usually expressed in terms of cylindrical coordinates r, θ and z, where r is the radial distance from the axis of the borehole, θ is the azimuth angle measured from the x-axis, and z is the position along the borehole axis.

The general solution for the stresses is as follows:

$$\sigma_r = \frac{\sigma_x^0 + \sigma_y^0}{2}\left(1 - \frac{R_w^2}{r^2}\right) + \frac{\sigma_x^0 - \sigma_y^0}{2}\left(1 + 3\frac{R_w^4}{r^4} - 4\frac{R_w^2}{r^2}\right)cos2\theta + \tau_{xy}^0\left(1 + 3\frac{R_w^4}{r^4} - 4\frac{R_w^2}{r^2}\right)sin2\theta + P_w\frac{R_w^2}{r^2} \qquad \text{(Eq. 2.21)}$$

$$\sigma_\theta = \frac{\sigma_x^0 + \sigma_y^0}{2}\left(1 + \frac{R_w^2}{r^2}\right) - \frac{\sigma_x^0 - \sigma_y^0}{2}\left(1 + 3\frac{R_w^4}{r^4}\right)cos2\theta - \tau_{xy}^0\left(1 + 3\frac{R_w^4}{r^4}\right)sin2\theta - P_w\frac{R_w^2}{r^2} \qquad \text{(Eq. 2.22)}$$

$$\sigma_z = \sigma_z^0 - \nu[2(\sigma_x^0 - \sigma_y^0)\frac{R_w^2}{r^2}cos2\theta + 4\tau_{xy}^0\frac{R_w^2}{r^2}sin2\theta] \qquad \text{(Eq. 2.23)}$$

$$\tau_{r\theta} = \frac{\sigma_y^0 - \sigma_x^0}{2}\left(1 - 3\frac{R_w^4}{r^4} + 2\frac{R_w^2}{r^2}\right)sin2\theta + \tau_{xy}^0\left(1 - 3\frac{R_w^4}{r^4} + 2\frac{R_w^2}{r^2}\right)cos2\theta \qquad \text{(Eq. 2.24)}$$

$$\tau_{\theta z} = (-\tau_{xz}^0 sin\theta + \tau_{yz}^0 cos\theta)\left(1 + \frac{R_w^2}{r^2}\right) \qquad \text{(Eq. 2.25)}$$

$$\tau_{rz} = (\tau_{xz}^0 cos\theta + \tau_{yz}^0 sin\theta)\left(1 - \frac{R_w^2}{r^2}\right) \qquad \text{(Eq. 2.26)}$$

where R_w is the well radius and P_w is the fluid pressure in the well.

For a borehole along a principal stress direction, the equations can be simplified. For a vertical well, the equations for the stresses at the borehole wall in cylindrical coordinates become:

$$\sigma_r = \frac{\sigma_H + \sigma_h}{2}\left(1 - \frac{R_w^2}{r^2}\right) + \frac{\sigma_H - \sigma_h}{2}\left(1 + 3\frac{R_w^4}{r^4} - 4\frac{R_w^2}{r^2}\right)cos2\theta + P_w\frac{R_w^2}{r^2} \qquad \text{(Eq. 2.27)}$$

$$\sigma_\theta = \frac{\sigma_H + \sigma_h}{2}\left(1 + \frac{R_w^2}{r^2}\right) - \frac{\sigma_H - \sigma_h}{2}\left(1 + 3\frac{R_w^4}{r^4}\right)cos2\theta - P_w\frac{R_w^2}{r^2} \qquad \text{(Eq. 2.28)}$$

$$\sigma_z = \sigma_V - 2\nu(\sigma_H - \sigma_h)\frac{R_w^2}{r^2}cos2\theta \qquad \text{(Eq. 2.29)}$$

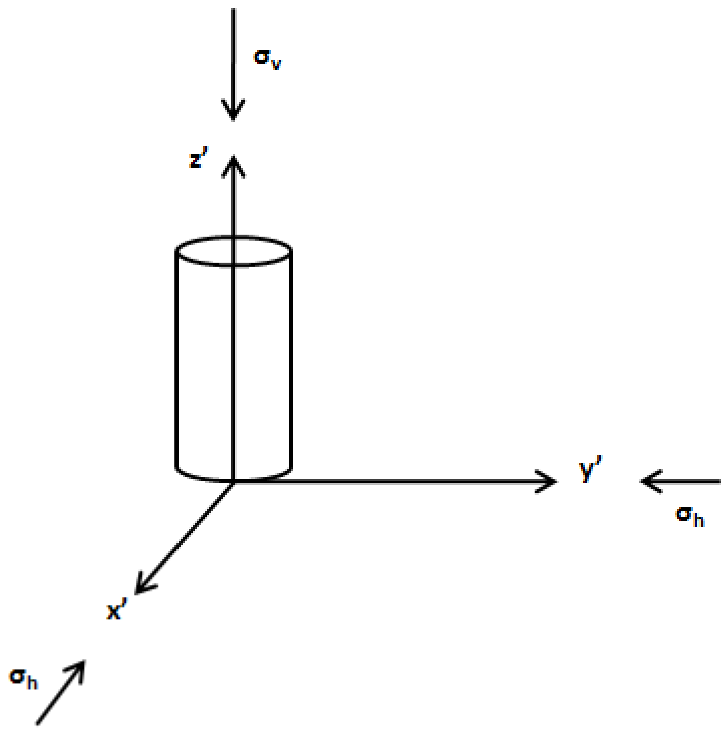

Figure 2-11 Illustration of a vertical well and a formation with isotropic horizontal stress ($\sigma_H = \sigma_h$)

The fracturing pressure is dependent on the effective tangential stress σ_θ'. The formation fractures if $\sigma_\theta{}' < -T_0$, where T_0 is the tensile strength of the material, often set to be zero for rocks. For the simplest case, as illustrated in Figure 2-11, where the borehole is vertical, the horizontal stresses are equal and the borehole wall is impermeable (mud filter cake is impermeable), the effective tangential stress at the borehole wall becomes:

$$\sigma_\theta' = 2\sigma_h - P_w - P_o \qquad \text{(Eq. 2.30)}$$

Inserting this result into the failure criterion for fracturing and assuming that T_0 is zero, the maximum well pressure before fracturing becomes

$$P_w^{frac} = 2\sigma_h - P_o \qquad \text{(Eq. 2.31)}$$

When assuming that the formation is laterally constrained and that the rock behaves linearly elastic, the following result is obtained:

$$\sigma_h' = \frac{\nu}{1-\nu}\sigma_V{}' \qquad \text{(Eq. 2.32)}$$

Using this result in equation 2.31, the fracturing pressure becomes:

$$P_w^{frac} = \frac{2\nu}{1-\nu}\sigma_V + \frac{1-3\nu}{1-\nu}P_o \qquad \text{(Eq. 2.33)}$$

This formula shows that when the pore pressure decreases, the fracturing pressure decreases when $\nu < 1/3$, and most reservoir rocks have a Poisson's ratio lower than this. Common values are $\nu = 0.15$ for chalk and $\nu = 0.25$ for sandstone.

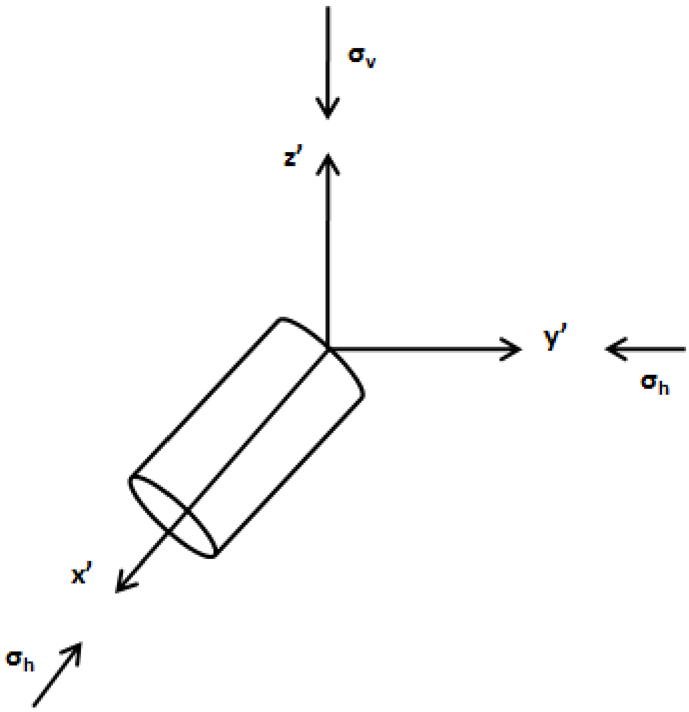

Figure 2-12 Illustration of a horizontal well along the x'-axis and a formation with isotropic horizontal stress ($\sigma_h = \sigma_h$)

This can also be done for a horizontal well along the horizontal stress, as illustrated in Figure 2-12, and when the same assumptions apply, the fracturing pressure in a horizontal well along a principal stress direction becomes:

$$P_w^{frac} = \frac{4\nu - 1}{1 - \nu}\sigma_V + \frac{2 - 5\nu}{1 - \nu}P_o \qquad \text{(Eq. 2.34)}$$

The formula shows that the fracturing pressure decreases when the pore pressure decreases if $\nu < 2/5$, which is even larger than in the first case and is therefore true for most reservoir rocks.

2.3 Smart-Well Technology

Smart wells or wells with intelligent completion are wells that are completed with permanent downhole measurement equipment or control valves or both (Gao, Rajeswaran, & Nakagawa, 2007). Smart well technology enables monitoring, remotely choking, or shutting off zones with poor performance without intervention. The first intelligent completion was installed at Saga's Snorre Tension Leg Platform (TLP) in the North Sea in August 1997. The system installed was WellDynamics' SCRAMS (Surface Controlled Reservoir Analysis and Management System), which typically is used to control the Infinitely Variable Interval Control Valve (IV-ICV™). These valves are controlled hydraulically with hydraulic force provided from the hydraulic control lines from surface; however, there are other systems that are fully electrical.

According to Gao et al. (2007) there are basically three benefits of smart well technology. The most important benefit is improved reservoir management. Intelligent completions enable multiple reservoirs, or multiple reservoir zones, to be accessed with a single well while avoiding cross-flow caused by different pressures in the producing layers. It also enables greater control of injected fluid in injection wells and thereby makes optimisation possible. Secondly, intelligent well completions can result in less time to first production. Multiple zone completion historically required complicated completion with multiple packers and tubing strings. If this was not possible the production had to be sequenced; produce from one zone first, then the others in turn typically starting with the deepest zone. Finally, the smart well technology gives reduced well intervention costs. Before the intelligent completion technology was developed the only method of obtaining downhole information was by logging, which requires well intervention. In wells without intelligent completion, interventions are performed periodically to measure downhole parameters such as pressure, temperature, and flow; however, because of high costs this may be done infrequently, and this lack of data may reduce the operators' ability to optimise production. The cost of well interventions is quite high, especially in deepwater or subsea wells, which means that the economic benefits from intelligent well technology is large.

A smart well system generally requires the following elements (Gao et al., 2007): flow control devices; feed-through isolation packers; control, communication and power cables; downhole sensors; surface data acquisition and control.

The initial systems used permanently installed downhole electronics and provided real-time pressure and temperature measurements. Systems for monitoring additional parameters, such as flow rate and water content were developed later. The downhole sensors used in these wells were controlled by electro-hydraulic control systems. The high pressure and high temperature downhole presented a challenge for these systems. The failure rates for these electronic systems approximately double with each 10 °C increase in temperature (Gao et al., 2007). The intelligent well completions are basically inaccessible once deployed and its value is therefore linked to the durability of the system; the components need to function for the life of the well. These early systems were not much used because of their low reliability.

2.4 Zonal Isolation

2.4.1 Introduction

A prerequisite for the intelligent systems necessary to control flow from each zone is sufficient zonal isolation. This is needed to avoid cross-flow between different zones and to control which zones to produce from or inject into. No zonal isolation means that zones cannot be independently inflow controlled. Intelligent completion systems, inflow control devices, multilaterals and inflow controlling interventions can be used where there is an effective annular isolation. Zonal isolation can be achieved in both cased-hole completions and open-hole completions. In cased-hole completions, zonal isolation is usually achieved by cementing, but swell packers could also be used in these applications. There are several technologies available to achieve annular isolation in open-hole sandface completions: inflatable packers, swell packers, solid expandable tubulars and chemical plugs (Ott & Woods, 2005).

2.4.2 Cementing

The zonal isolation in cased hole completions is usually achieved by cementing the annulus. A good cement job is needed to ensure zonal isolation. In reservoirs with depleted zones as potential fluid loss zones, getting a good cement job can be difficult.

Cementing of long horizontal sections is difficult. The most difficult cementing objective to achieve is zonal isolation (Gai, Summers, Cocking, & Greaves, 1996). Zonal isolation is particularly difficult to achieve because the cement slurry has to be placed uniformly in the annulus over the entire length where isolation is required. Important issues for cementing long horizontal wells and achieve zonal isolation include: hole cleaning, centralization, design cement to minimise ECD, and use cement slurry with no free water and particle settlement to avoid channels developing on the high side. Gai et al. (1996) concluded from several case studies that good quality cement jobs can be achieved by ensuring that all designed engineering parameters are within the required range, and that centralizers locally improved the cement job quality.

To ensure a good cement job there are several issues than needs to be addressed, and the main issues are (Rahman & Zulkafly, 2004): (1) well conditioning, (2) pipe centralization, (3) mud removal, and (4) cement slurry design.

The well geometry needs to be known; the hole size is an important factor to consider to be able to determine the necessary cement volume. This can be determined from a caliper log. Another important factor is the mud conditioning. The mud needs to be conditioned before removing the drillpipe to avoid the mud to gel during the period before running casing. After the casing is landed the mud should be conditioned again to remove cuttings, break the gel and lower the viscosity.

Pipe centralization is important to ensure an annulus with open flow paths. If the pipe is not centralized, the pipe will trap mud on the low side of the hole. This mud will prevent cement in these parts, and thereby reducing the quality of the cement job. In highly deviated and horizontal wells the centralization is difficult to achieve.

The mud has to be removed in order to get a good cement job coverage and bond around the pipe. Optimization of the chemical wash and spacer is essential to remove the mud before the displacement with cement begins.

Slurry design also plays an important role in ensuring good cement jobs. To achieve zonal isolation, especially in highly deviated and horizontal sections, the cement slurry needs certain properties: (1) the slurry needs to have zero free water to prevent channels on the high side, (2) it must have rheological properties so that it is able to flow through the narrow annulus on the low side of the well, and (3) it must have low fluid loss to prevent dehydration when flowing across permeable zones.

Cementing expandable liners

When cementing expandable liners, there are several other requirements in addition to the factors that need to be considered for cementing. Some of the requirements are (Rahman & Zulkafly, 2004):

- The cement slurry usually needs extended thickening time for liner expansion operation in addition to the time for cement slurry mixing and placement. If the cement stays in static conditions too long, the performance of the additives typically deteriorates significantly. Particles and other solids may not stay suspended and the cement slurry segregates. Free water may start to appear and the thickening time becomes unpredictable. The result would probably be a poor quality cement job and no zonal isolation.
- The pump rate needs to be kept low to prevent the slurry from lifting cuttings and mud cake out of the annulus and into the overlap section at the liner top. If this happens, the particles could fall into the liner and cause problems to retrieve the expansion assembly. In addition, if the particles settle in the overlap section they may prevent full expansion of the liner and a seal will not be achieved.
- No centralisers will be used. The clearance between the expandable liner and the previous casing is very small, and it is not possible to use centralisers.
- The slurry volume is based on post-expansion liner diameter. When expanding the liner, the cement level rises because the annular volume decreases. It is important that the cement does not overflow into the liner, thus preventing a seal.
- Pipe movement is not possible. Pipe movement would possibly cause damage to the expandable liner at the previous casing shoe. There are elastomers at this position that seals between the casing and the expandable liner when it is expanded, and these may get damaged if reciprocating or rotating the pipe.
- Cement slurry must have excellent stability for an extended period in static condition. The slurry needs to be stable and it needs to maintain its fluidity to ensure that the expansion process can be done. If the slurry loses its fluidity and the static gel increases, the slurry may induce losses to the formation instead of rising upwards. The top of cement may then be at the pre-expanded level because the slurry is being squeezed into the formation, and this prevents zonal isolation in parts of the section.

2.4.3 External Casing Packers

The inflatable packers are often referred to as external casing packers (ECP) or annulus casing packer (ACP), however; a mechanical packer can also be used as a non-inflatable alternative. An example of a mechanical packer is Baker's MPas packer. This packer can be used together with BetaBreaker valves in open-hole gravel packs. This setup leaves an open area without gravel around the packer and thus allowing it to expand and seal the annulus.

Inflatable packers are activated by pumping from surface through the service string and into the inflatable element. The inflatable packers are used on the outside of the casing to seal off formations or to protect zones. These packers can be run on casing or in between sections of sand control screen, slotted liner, stand-alone screen, selective completions with sliding sleeves, and open-hole gravel packs. The string is run to the setting depth and then the packers are expanded against the borehole wall by hydraulic pressure or fluid pressure from the well. Cement is usually used for permanent applications. The packers' ability to hold pressure is dependent on the radial force from the packing element on the borehole wall. If the cement shrinks when it is set, the packer may not have enough radial force to ensure a pressure-tight seal.

2.4.4 Swellable Packers

There are several types of swellable packers. Swellable packers may be a vulcanised rubber element on a pipe, or it can be an element that is slipped on to a pipe. The packer will swell and seal the annulus around a pipe to isolate reservoir zones in both open and cased holes. The swell packer system is set in a single trip; it has no moving parts and does not require any downhole or surface activation. Packers are available for both oil- and water-based systems. Swellable packers have been used in several applications: to establish zonal isolation in liner completions or open-hole completions, as a production separation packer, and as a part of an expandable open-hole clad. Swellable packers can be used on standard pipes or on expandable pipes to create zonal isolation.

There are basically two mechanisms that the packers use to swell, depending on whether it swells in oil or in water. Packers that swell in oil use a process called diffusion and packers that swell in water use a process called osmosis.

2.4.5 Expandable Solutions to Zonal Isolation

There are several types of expandable tubular solutions for zonal isolation. One example is Enventure's Openhole Clad (OHC) system, which is a solid expandable tubular with elastomers that seals directly against the formation. The system consists of an expandable pipe for the length to be isolated, and a pre-expanded section with a float assembly and expansion cone. Another example of expandable technology that can be used for zonal isolation is the Baker SealEXX™ openhole production patch, which is based on a similar principle as the OHC system. Weatherford's expandable zone isolation (EZI) joints and their expandable sand screen (ESS) joints can be used together to provide zonal isolation. Both the EZI joints and the ESS joints can be expanded against the formation. Elastomers or swelling elastomers can be used on solid expandable liners to create zonal isolation when they are not cemented.

Read's Zonal Isolation Barrier (ZIB™) is a solid expandable device that acts as an external casing packer, as shown in Figure 2-13. The ZIB™ can be used in cased or open hole and is expanded against the casing wall or formation, preventing annular flow. The ZIB™ is expanded using HETS technology (Hydraulically Expandable Tubular System) and can be expanded when run or as a contingency when needed.

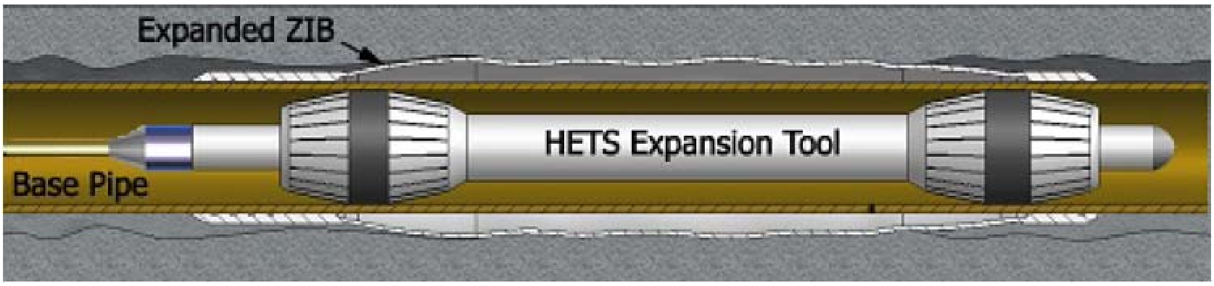

Figure 2-13 The Zonal Isolation Barrier expanded against the formation using the HETS Expansion Tool (Mathiassen, Skjerping, & Hazel, 2007)

2.5 Expandable Technology

2.5.1 Introduction

Expandable tubulars have been incorporated in original well design, installed to mitigate unexpected drilling problems in troublesome zones, turned existing wells into larger bore producers, and combined with other new technologies such as intelligent well completions.

There are basically two different concepts of well geometry: conventional telescoping geometry, and monobore. The conventional well geometry is based on drilling until a casing has to be set to seal off the formation, and then cement this casing string before drilling further with a smaller bit. This process is repeated until the target depth is reached. In this well geometry the hole size decreases for each section, and the top section need to have a large diameter to be able to reach the reservoir with a hole size which is economically viable for the given reservoir. Small tubing may be a production limitation for the well. This can be illustrated by looking at the change in flow rate as a function of diameter for a given pressure drop. Drilling Data Handbook (Gabolde & Nguyen, 2006) gives equations for pressure drop, and in turbulent flow for a Newtonian fluid or a Bingham fluid the pressure drop can be calculated from the following equation

$$\Delta P = \frac{Ld^{0.8}\mu^{0.2}Q^{1.8}}{C_P D^{4.8}} \qquad \text{(Eq. 2.35)}$$

where L is the length of the pipe, d is the specific gravity of the fluid, μ is the fluid viscosity, Q is the flow rate, D is the inner diameter of the pipe, and C_p is a conversion factor depending on which units that are used. To examine the change in flow rate when the diameter changes, the pipe length and the fluid properties can be held constant. The equation then becomes

$$\Delta P = \frac{Ld^{0.8}\mu^{0.2}}{C_P} \cdot \frac{Q^{1.8}}{D^{4.8}} = C\frac{Q^{1.8}}{D^{4.8}} \qquad \text{(Eq. 2.36)}$$

where C is the constant containing the fluid properties, the pipe length and the conversion factor.

If the pressure drop is considered constant, a relation between the flow rate and the diameter can be found

$$\Delta P_0 = C\frac{Q_0^{1.8}}{D_0^{4.8}} = \Delta P = C\frac{Q^{1.8}}{D^{4.8}}$$
$$\frac{Q}{Q_0} = \left(\frac{D}{D_0}\right)^{4.8/1.8} \cong \left(\frac{D}{D_0}\right)^{2.67} \qquad \text{(Eq. 2.37)}$$

where Q_0 and D_0 represents reference values. This relation is shown graphically in Figure 2-14. The graph shows that the effect of production tubing diameter on the production capacity is significant. If the diameter increases by 10 % the flow rate increases by 29 % (green line in the graph), and if the diameter increases by 50 % the flow rate is almost tripled (red line in graph).

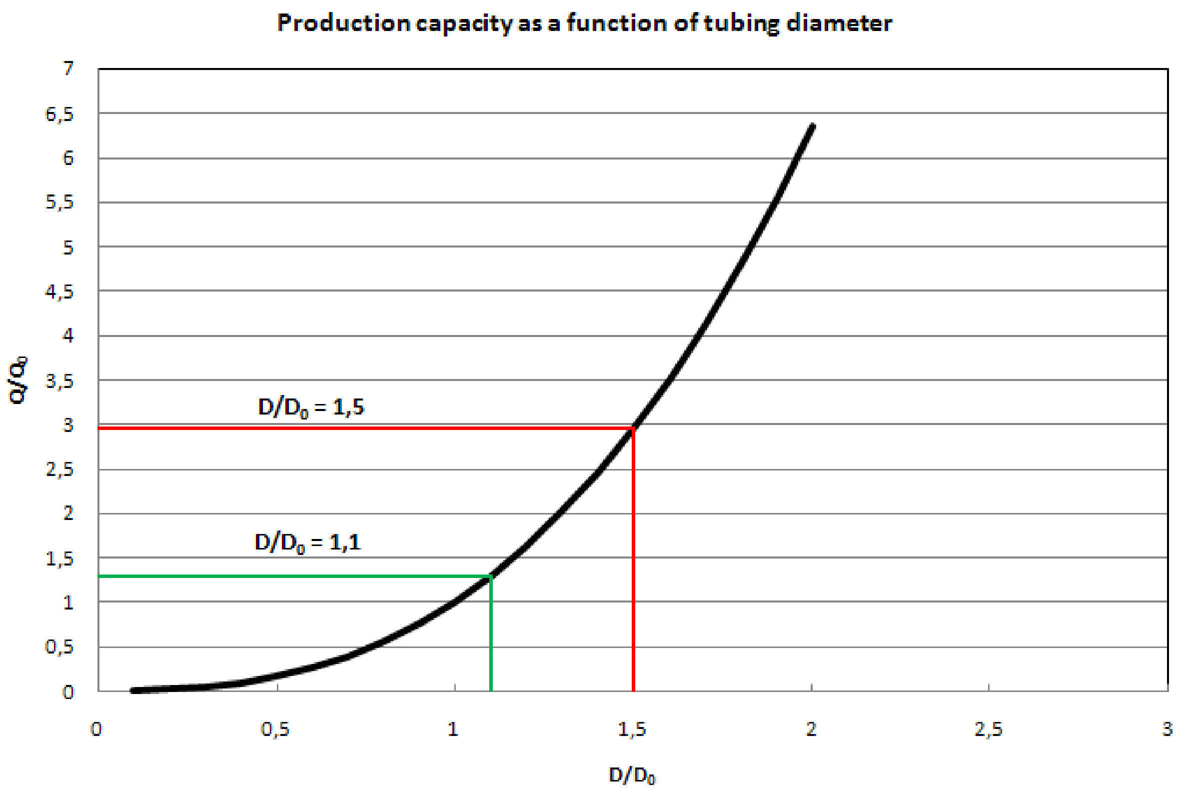

Figure 2-14 Effect of production tubing diameter on production capacity

In a true monobore well the inner diameter would be the same from surface to the total depth. The technologies to drill and case these wells are not available now; however, with the development of expandable liners there is a possibility in making two or more sections monobore.

Expandable technology gives several advantages over the conventional method. It gives the opportunity to drill slimmer wells and thereby reduce the cost of materials needed to construct wells. Another benefit is the possibility to reach the reservoir with a larger dimension and thereby increase the production deliverability of the well. Expandable casing or liner technology also allows operators to drill deeper wells or to extend the length of deviated wells. For challenging reservoirs in particular, it is an advantage to have the possibility of using expandable technology to be able to case off problem zones without loss of hole size.

There are several methods of installing expandable liners. One method is to set the previous casing or liner, often called the base casing, with an oversized shoe, called a recess shoe. The expandable liner is then run and expanded into the shoe, giving a monobore section. To do this the recess shoe and the next hole section has to be drilled and underreamed to a larger dimension than the bit to allow for expansion. Another method is to expand the liner into the base casing inner diameter and not using an oversized shoe. If the overlap is not expanded, this will result in a reduction of the inner diameter; however, the overlap can also be expanded, which may result in a monobore section, depending on the expansion ratios available.

The expansion process typically includes (1) running an expandable casing or liner into the wellbore and then (2) hydraulically pushing or pulling a cone, of a larger diameter than the original inner diameter of the casing or liner, through the pipe and thereby expanding it downhole. Rotary expansion tools can also be used. The cone is situated in what is called a launcher. The launcher has a larger OD than the pre-expanded casing, and one has to make sure that the launcher can pass through the base casing. Other important aspects to consider are the properties of the pipe after expansion.

2.5.2 Applications

There are several applications for expandable technology. The applications can be divided into two main groups: cased-hole applications and open-hole applications.

In cased-hole applications, expandable technology is typically used to blank off sections of perforations to minimize water inflow, or it can be used to repair damaged or corroded casing. The expandable solutions have also been used to reinforce the casing and reline entire wellbores. Since the total wall thickness may be increased when the wall thickness of the expanded pipe is added to the wall thickness of the original casing, the burst strength of repaired casings is usually higher than the original casing alone, and it thereby enables stimulation treatments, wellbore treatments and hydraulic fracturing operation (Enventure Global Technology, 2008a). Figure 2-15 shows one application of Baker Oil Tools EXPatch™ casing cladding system, where it is used to shut off water production by blanking off a certain length of perforations. The clad length can be customised to the specific situation where it is needed. The expandable technology minimises the restriction caused by the clad by expanding it to the inner diameter of the casing.

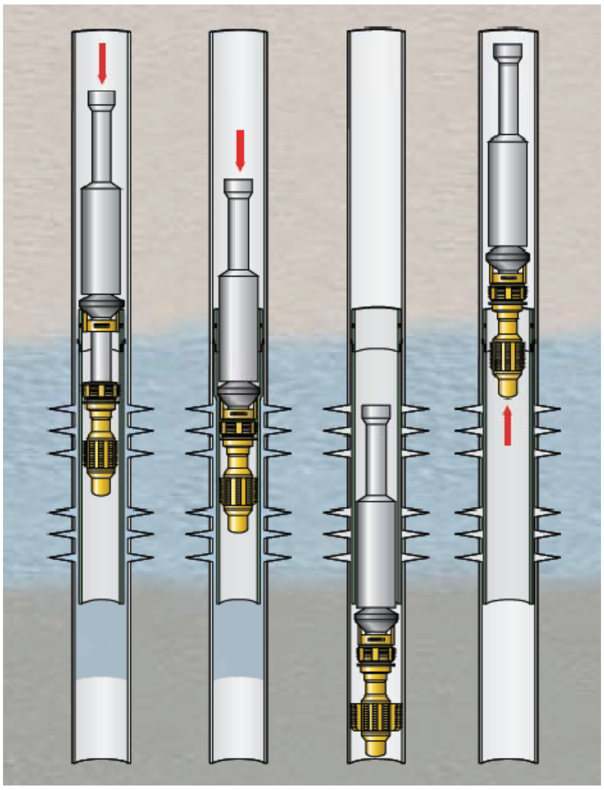

Figure 2-15 Baker Oil Tools EXPatch™ casing cladding system (Baker Oil Tools, 2007)

In open-hole, an expandable liner can be used to seal off problem zones, either as a solution to unexpected problems and used as a contingency, or used in the initial well design. This offers the possibility of casing off zones, while still maintaining the inner diameter of the previous casing, thus being able to reach the reservoir with a larger hole. Figure 2-16 shows the principle behind the deployment of expandable liners.

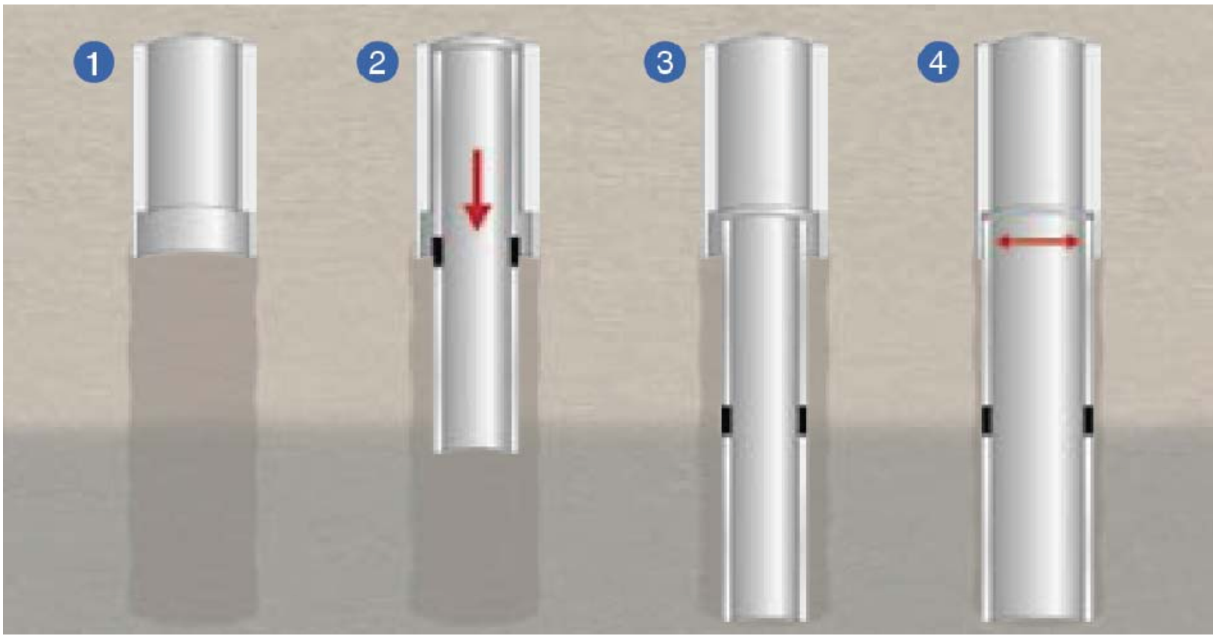

Figure 2-16 Baker Oil Tools linEXX™ expandable liner system (Baker Oil Tools, 2004a)

There are also expandable patches that can be used in open-hole to seal water-producing zones. An example of such an application is shown in Figure 2-20. In this case, the expandable clad has been used to seal off two water producing zones, while producing from zones in between.

Expandable technology is also being used in liner hangers. A conventional liner hanger has several moving parts; the need for these is eliminated in an expandable liner hanger. There are two key functions that a liner hanger should provide: (1) sustain the weight of the liner, and (2) isolate pressure differentials. Figure 2-17 shows an illustration of the principle of a conventional liner hanger and an expandable liner hanger, here represented by Halliburton's VersaFlex®. The conventional liner hanger uses slips to hold the weight and a liner hanger top packer to isolate pressure differentials. Expandable liner hangers use elastomeric elements on the outer diameter of the liner hanger to create a seal against the base casing and to take the weight of the liner below. A seal is made by pushing a cone and thus expanding the liner hanger body outwards to the base casing.

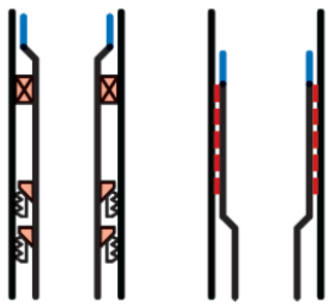

Figure 2-17 Illustration of a conventional liner hanger (left) and an expandable liner hanger (right) (Mota, Campo, Menezes, Jackson, & Smith, 2006)

The aforementioned expandable solutions are solid expandables. In addition to the solid expandables, there are also other products available, such as expandable sand screens. The expandable screens provides the well with a means of sand control, reduces the annular flow, and increases the inner diameter as compared to regular screens and thereby increases the production potential. Figure 2-18 and Figure 2-19 show examples of such expandable screens. The conventional approach to complete and produce from multi-zone reservoirs is to set and cement casing to provide zonal isolation. The zones to be produced are perforated prior to installation of the screen and, if needed, a gravel pack is performed. This method produces high completion skins and it also reduces the inner diameter (Innes, Morgan, Macarthur, & Green, 2005). Expandable screens are in direct contact with the formation and thereby reduces the completion skin, which means that the productivity increases (Innes et al., 2005).

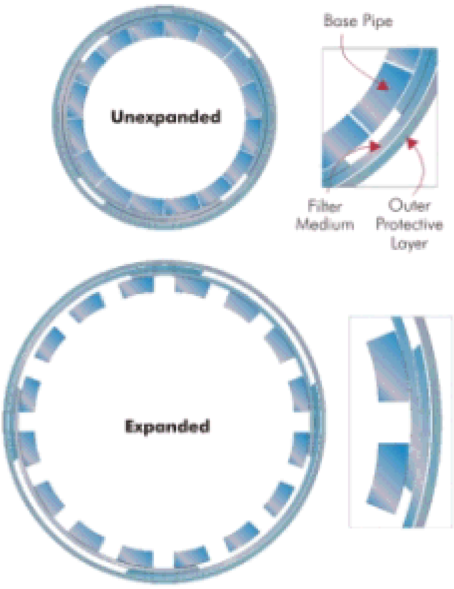

Figure 2-18 ESS™ Expandable Sand Screen (Weatherford, 2008)

Figure 2-19 EXPress™ Screen (Baker Oil Tools, 2009)

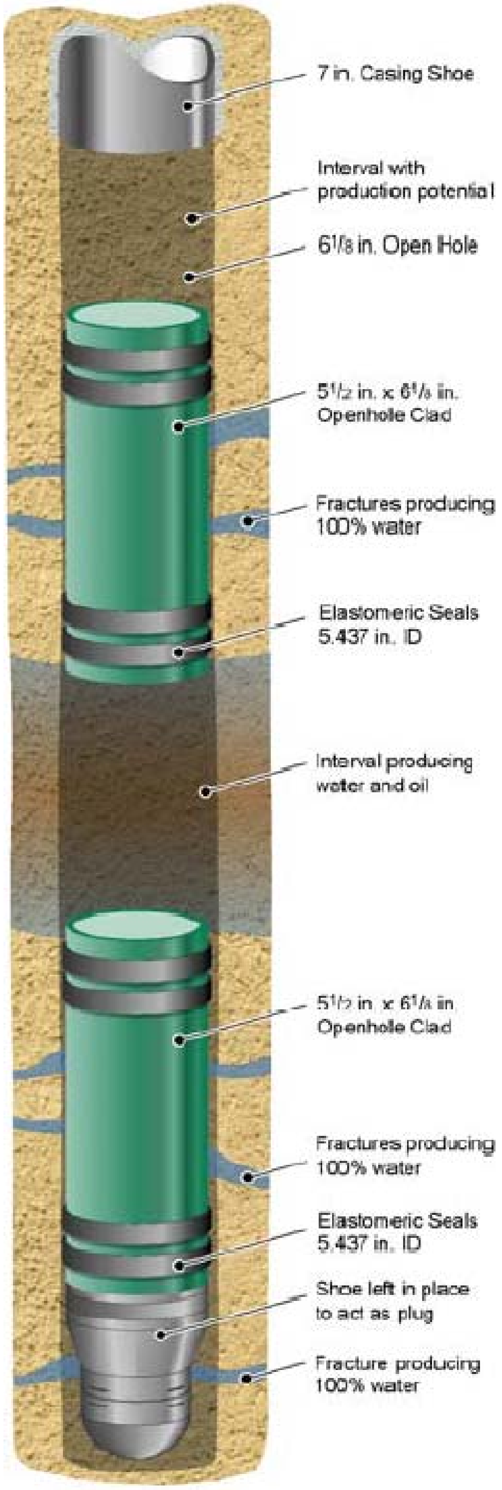

Figure 2-20 SET® Openhole Clad System (Enventure Global Technology, 2008b)

Expandable technology can be installed through milled casing windows to minimise the reduction of diameter in side-tracks or slot recovery operations. The reason why this technology has advantages here is that it may enable the well due to an economic criterion. For the well to be economically viable it may be necessary to reach the reservoir with a certain minimum inner diameter. See Figure 2-14 for the effect of the diameter on production capacity. For conventional casings, the inner diameter is reduced significantly. Use of an expandable liner may limit the reduction in diameter and thus enable a more economic production.

When a liner is run through a milled casing window it may get damaged. The damage may not be of importance for conventional casings, but if it is to be expanded the pipe may fracture (Waddell & Schuurmans, 2004). Damage will represent areas of increased stress in the material, and may therefore cause the pipe to fracture during the expansion process. To avoid getting critical damage to the pipe when running it through the milled window, the window is enlarged. There have been performed lab tests, field trials and commercial installations that shows that expandable technology can be used through milled casing windows (Waddell & Schuurmans, 2004).

2.5.3 Pipe Deformation and Material Selection

To expand a pipe and for the pipe to maintain the new shape, the stress has to exceed the yield limit, otherwise it would go back to its initial shape. This means that the stress state is in the plastic region of the material during expansion, and the pipe is permanently deformed. In this process it is important that the stress does not exceed the ultimate strength. The expansion process is typically done by pulling or pushing a cone through the pipe and thus expanding the inner diameter of the pipe to the diameter of the cone. This process is called cold-working the material because additional heat is not supplied. In addition to expanding the pipe with a cone, hydraulic pressure can be applied to add a force to the cone. The hydraulic pressure must be lower than the burst pressure of the pipe for the pipe to maintain pressure integrity. When applying pressure inside the pipe a residual stress will be introduced in the pipe wall which may affect the pipe properties, similar to an autofrettage process (see 2.1.10 Autofrettage).

When selecting the material to use in expandable pipes, there are basically three states in which the properties are important to consider; pre-expansion, during expansion and post-expansion. The most common criteria used to classify the material properties in these states are toughness, work hardening, and the Bauschinger effect (Jabs, 2007).

For the pre-expanded pipe, the main criterion is its ability to resist tearing during the expansion process, i.e. the material needs to be sufficiently ductile. It is also important not to damage the pipe before it is expanded. During transportation, handling and installation of the expandable pipe, external markings may develop. When expanding the pipe, the areas where there are markings, will be areas of increased stress and may cause the pipe to rupture at these locations (Stockmeyer et al., 2006).

To be able to expand the pipe, the material's ability to flow without exceeding its ultimate tensile strength is an important property. When the pipe is expanded, the material yield stress is exceeded; however, the ultimate tensile strength should not be exceeded. If the ultimate tensile strength is exceeded, the material will fail. The strain, or elongation, in the material before failure can be found if the ultimate tensile strength and the stress-strain relationship of the material are known. High elongation and the final yield strength are important parameters for the material used in expandable pipes.

2.5.4 Expansion Methods

There are basically two methods of pipe expansion: the cone can be pushed or pulled through the pipe, or the pipe can be moved over the cone while the cone remains still. Figure 2-21 illustrates the different expansion methods. The most used method is to pull or push the cone through the liner as illustrated in the figure, denoted bottom up and top down respectively. Pressure can be applied to produce a force to push the cone, and this is often called hydraulic expansion. Scoping, which is not much used, but a field trial has been done (Moore, Wright, Winters, & Daigle, 2003), is a method where the cone remains still while the liner is pushed down, as illustrated in the figure.

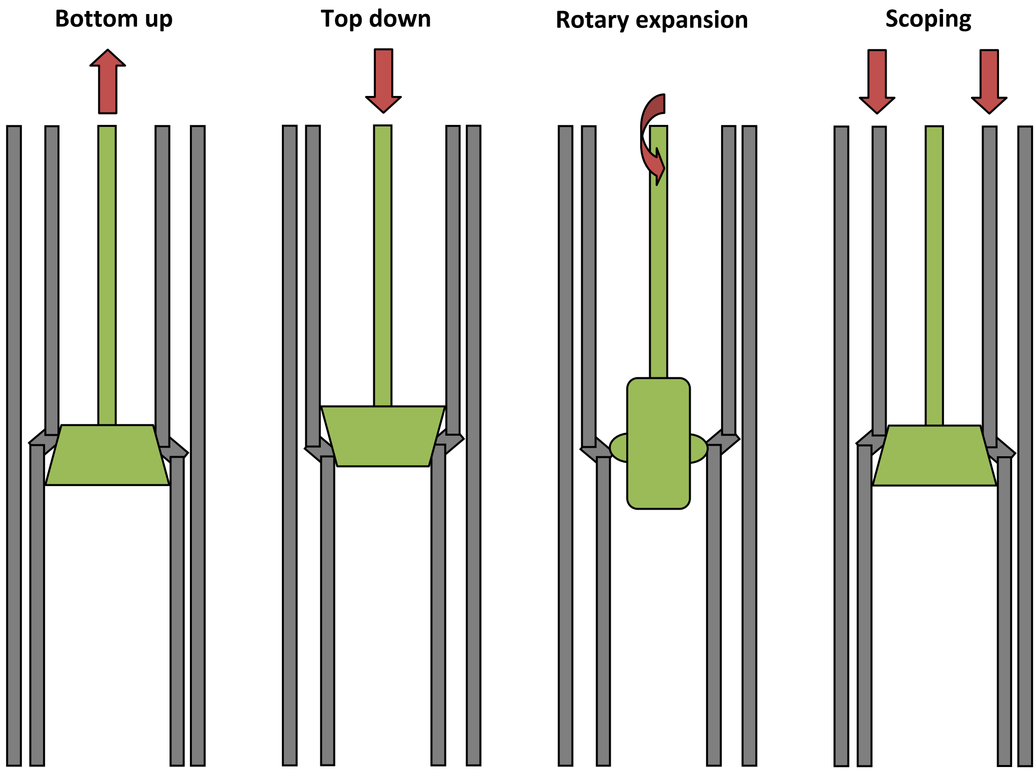

Figure 2-21 Expansion methods

Fixed cone expansion is an extrusion process in which a cone, often called a swage, is used to expand the pipe. The cone has a diameter slightly larger than the inner diameter of the expanded pipe. Figure 2-22 shows an example of a fixed cone expansion process and the swage used. Usually the pipe is fixed in position while the cone is drawn towards the free end, a process which permanently stretches the circumference of the pipe. When the circumference is enlarged, the length of the pipe is usually reduced, depending on the end conditions of the pipe. If one end or both ends are free the length may be reduced, however, if both ends are fixed the length will not change. When performing calculations on the shortening of the pipe, the volume is usually assumed to be constant in the entire process; however the steel volume may change when it is loaded.

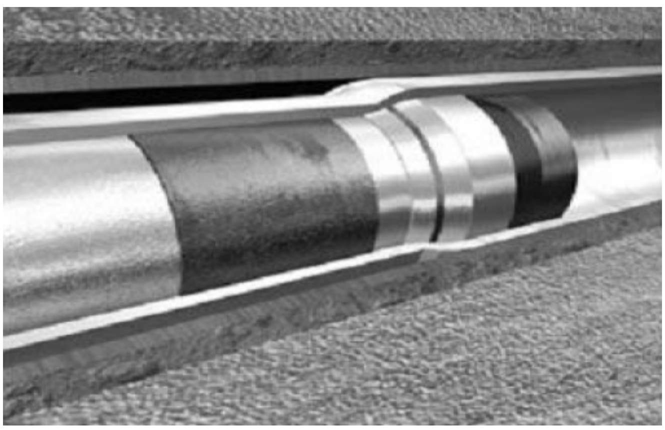

Figure 2-22 Swage used in fixed cone expansion (Innes, Metcalfe, & Hillis, 2004)

There are also rotary expansion tools available, which usually consist of one or more rollers that produce a radial force against the pipe's inner surface. The contact stress is sufficient to overcome the yield strength and permanently expand the pipe. In order to apply this force around the entire circumference of the pipe, the tool is rotated. This method reduces the shortening of the pipe as compared to fixed cone expansion. Since the length reduction is less, the wall thickness decreases, which means that the collapse pressure of the pipe is correspondingly reduced. Rotary expansion also reduces the axial load necessary to expand the pipe, and typical axial loads are approximately 20 % of those associated with fixed cone expansion (Innes et al., 2004). There are two basic categories of rotary expansion: fixed rotary expansion and compliant rotary expansion.

In a fixed roller system, the expansion characteristics are dictated by the geometry of the rolling elements. In a compliant system, shown in Figure 2-23, the rollers are connected to pistons. The pistons are activated by the internal tool pressure, and this makes it possible to regulate the radial force. This gives the possibility to produce a range of expansion ratios, and not necessarily a perfectly circular shape. The latter ability may be useful in open-hole zonal isolation devices since the wellbore usually is not perfectly circular in shape.

Figure 2-23 Rotary compliant expansion tool (Innes et al., 2004)

Scoping differs from the conventional expansion method. During scoping expansion the cone does not move; the pipe is moved downwards over the cone and is thus expanded as illustrated at the rightmost part of Figure 2-21. Scoping allows an expandable liner to move downward while the inner work string and expansion cone remain still (Moore et al., 2003). Continuous motion of the pipe reduces the risk of stuck pipe due to differential sticking. During scoping expansion the liner shoe starts a considerable distance from the bottom. The liner shoe is then pumped towards the well bottom continuously while the work string with cone remains still.

2.5.5 Post-Expansion Properties

The yield strength of an expanded pipe is increased in the work hardening process. As shown previously, the burst pressure depends directly on the yield strength of the material. As a consequence of this, the burst resistance of the pipe may increase after the pipe is expanded, depending on the wall thickness reduction. However, the same does not apply for collapse resistance. The collapse of a pipe is somewhat more complex, and there are different failure modes in collapse depending on the D/t ratio and the yield strength. For thin-walled pipes, the collapse resistance does not depend on the yield strength, but on the elastic modulus of the pipe, in addition to diameter and wall thickness. The elastic modulus is a property that is not affected by the expansion process. Since the pipe wall gets thinner in the process and its diameter increases, the collapse resistance is expected to decrease, and this is also observed from tests performed (Butterfield, Flaming, Lebedz, Thigpen, & Hill, 2007).

To illustrate the reduction in collapse resistance the following situation can be considered: assume that the pipe has a large D/t ratio such that it fails elastically, the Poisson's ratio and the elastic modulus are constant, and that the steel volume is constant. The collapse resistance P_E in the elastic range can then be calculated from

$$P_E \cong \frac{C}{\left({}^{D}/_{t}\right)^3} \qquad \text{(Eq. 2.38)}$$

where C is a constant, D is the outside diameter of the pipe and t is the wall thickness. From the assumptions stated above, the following simplification can be made to find an approximate relation between the pre-expanded diameter D_0, thickness t_0 and length L_0, and the post-expanded diameter D, thickness t and length L for large D/t ratios:

$$ {}^{t}/_{t_0} \cong \frac{L}{L_0} {}^{D_0}/_{D} \qquad \text{(Eq. 2.39)}$$

The constant C is equal for the pre-expanded pipe and the post-expanded pipe since the elastic modulus and Poisson's ratio does not change. The change in collapse resistance can then be estimated from

$$P_E\left({}^{D}/_{t}\right)^3 \cong C \cong P_E^0\left({}^{D_0}/_{t_0}\right)^3 \qquad \text{(Eq. 2.40)}$$

and combining these equations the following result is obtained

$$\frac{P_E}{P_E^0} \cong \left(\frac{L}{L_0}\right)^3\left(\frac{D_0}{D}\right)^6 \qquad \text{(Eq. 2.41)}$$

There have been several tests performed and the length reduction recorded varies from approximately 4 % to 7 % (Filippov et al., 1999; Innes et al., 2004; Moore et al., 2003).

Figure 2-24 shows equation 2.41 graphically, where the relative collapse pressure is plotted as a function of the inverse expansion ratio of the outer diameter for zero length reduction, which represents a worst case condition with respect to collapse, and for 5 % length reduction. The graph shows that the collapse resistance is reduced significantly when the pipe is expanded. If the outer diameter is expanded by 10 % (green line in graph) the collapse resistance is reduced by approximately 44 % for zero length reduction and 34 % for 5 % length reduction. If the outer diameter is expanded by 20 % (red line in graph) the collapse resistance is reduced by approximately 67 % for zero length reduction and 61 % for 5 % length reduction. Note that the blue curve in Figure 2-24 is calculated with a constant length reduction of 5 %. This simplification may not be accurate because the length reduction varies with expansion ratio; however, it is included in the figure to show that the collapse pressure with a certain length reduction is higher than for no length reduction.

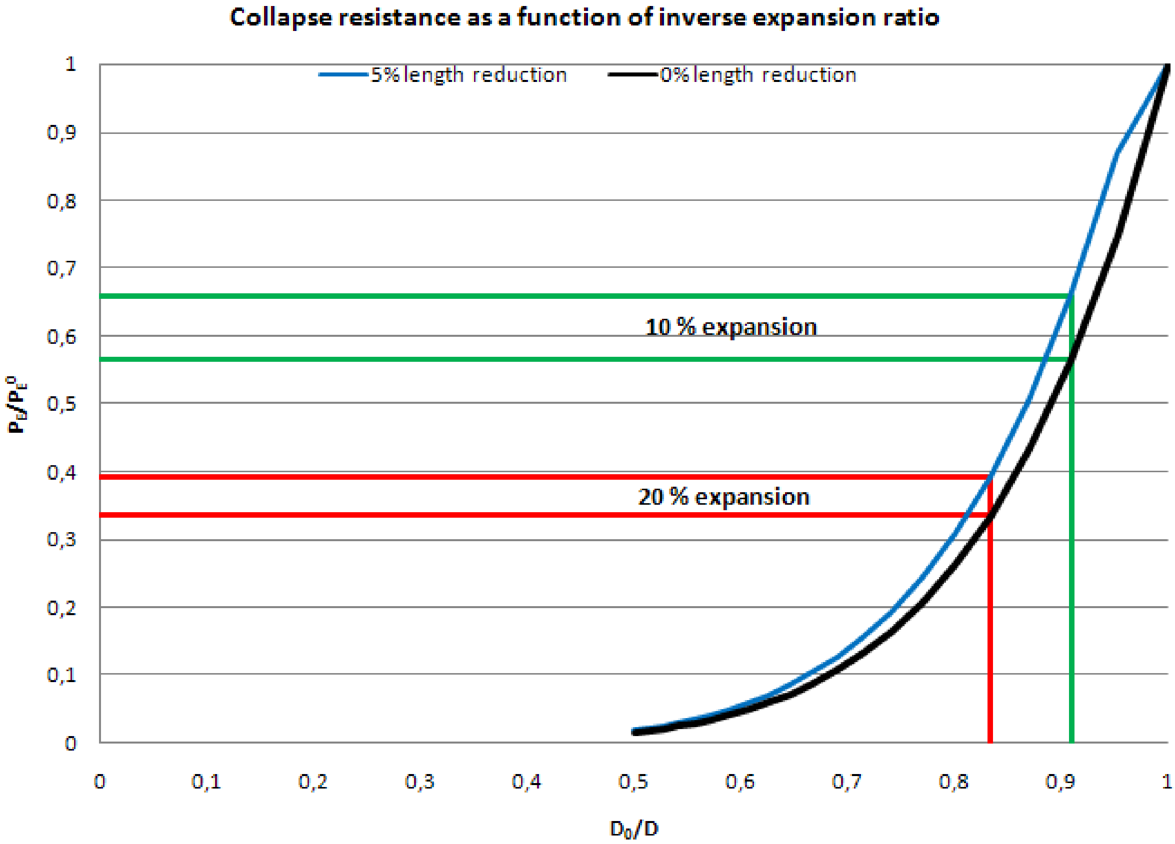

Figure 2-24 Collapse resistance as a function of inverse expansion ratio

Limited information about the pipe's post-expansion properties may create uncertainty in the application of expandable technology. Depending on the application it may be imperative to establish accurate properties for the pipe after the expansion process. The collapse resistance of an expanded pipe may be of special interest, for instance when cementing of the pipe is required or it is used to seal off a high pressure zone in a multi-zone reservoir with depleted zones. The collapse resistance of a pipe is usually calculated using the API recommended equations. These equations do not consider any residual stress that the expansion process may introduce to the material. There have been tests performed on pipes with various expansion ratios and a range of pipe sizes to better be able to determine the post expansion properties, the collapse resistance in particular (Butterfield et al., 2007). The tests investigated the effects of the expansion process on the collapse resistance. Post-expanded specimens from six different pipe sizes, two different manufacturers and seven different expansion ratios were evaluated; a total of 105 specimens where collapsed. These tests give data for D/t ratios ranging from approximately 18 to 43, and for different expansion ratios. The D/t ratio is a critical parameter in determining the collapse resistance of a pipe. The actual collapse pressures were compared to the API collapse resistance values calculated with post-expansion D/t ratio. The following list gives some of the observations from the tests:

- For the low range of D/t ratios (19 to 24), the post-expanded collapse resistance was 7 % on average less than API calculated value, and the largest deviation was 14 % below API calculation.
- The difference between the API calculated values and the actual collapse resistance decreases as D/t increases until D/t becomes 33 where the actual collapse resistance becomes higher than API calculated and trends higher.
- For the high range of D/t ratios (33 to 43) the post-expanded collapse resistance was 6 % higher than API calculated values on average and the best sample was 17 % higher than the API calculated value.
- For increasing expansion ratios the difference between the actual collapse resistance and the API calculated values decrease.

The results help determine a more accurate collapse pressure for pipes that have been expanded.

The graphs in Figure 2-25 shows the calculated collapse pressure using API equations and the given design collapse pressures by one of the service providers. The green line shows the collapse pressures calculated using the API collapse equations, and the red line shows the design collapse pressures given by the service provider. The design collapse pressures are a result of test data. The yield strength of these pipes is 80 ksi.

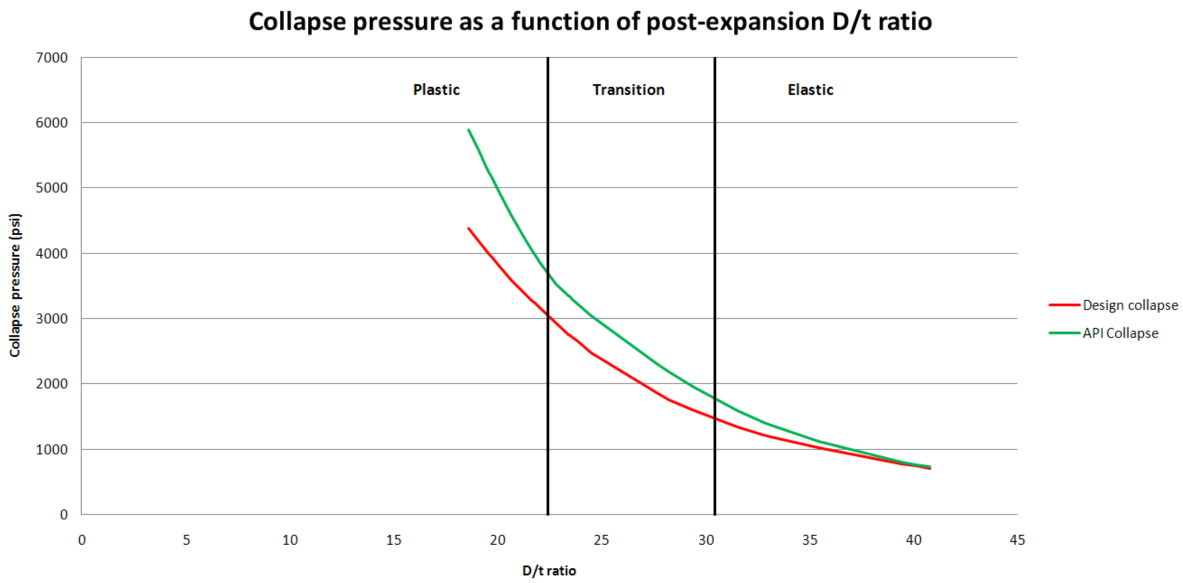

Figure 2-25 Collapse pressure as a function of post-expansion D/t ratio for one service providers expandable liners.

The graphs in Figure 2-25 shows the same trend as observed by Butterfield et al. (2007). The difference between the calculated collapse pressure and the observed collapse pressure decrease as the D/t ratio increases. As Table 2-5 shows, the deviation is highest for low D/t ratios. The tests by Butterfield et al. showed that the observed collapse pressure was higher than API calculations for high D/t ratios; however, in this case the calculated collapse pressures are consistently higher than the design collapse pressures. This may be because the design collapse pressures include a certain safety factor which makes it lower than the tests actually showed.

Pre-expansion		Post-expansion				Expansion ratio		Collapse pressure			Deviation
OD (in.)	ID (in.)	D/t	OD (in.)	ID (in.)	t (in.)	OD (%)	ID (%)	Given (psi)	Calculated (psi)	Failure mode	
4,250	3,750	18,626	4,526	4,040	0,243	6,5 %	7,7 %	4380	5896,6	Plastic	26 %
4,250	3,750	19,075	4,597	4,115	0,241	8,2 %	9,7 %	4190	5586,0	Plastic	25 %
5,500	4,892	19,445	5,785	5,190	0,298	5,2 %	6,1 %	4050	5340,5	Plastic	24 %
4,250	3,750	19,615	4,688	4,210	0,239	10,3 %	12,3 %	3980	5231,2	Plastic	24 %
5,500	4,892	19,736	5,842	5,250	0,296	6,2 %	7,3 %	3940	5154,1	Plastic	24 %
5,500	4,892	20,129	5,918	5,330	0,294	7,6 %	9,0 %	3790	4911,3	Plastic	23 %
5,500	4,892	20,662	6,023	5,440	0,292	9,5 %	11,2 %	3600	4596,5	Plastic	22 %
5,500	4,892	21,307	6,147	5,570	0,289	11,8 %	13,9 %	3390	4236,8	Plastic	20 %
5,500	4,892	21,652	6,214	5,640	0,287	13,0 %	15,3 %	3280	4053,2	Plastic	19 %
6,000	5,390	21,810	6,445	5,854	0,296	7,4 %	8,6 %	3230	3970,5	Plastic	19 %
6,000	5,390	22,034	6,489	5,900	0,295	8,2 %	9,5 %	3160	3856,3	Plastic	18 %
6,000	5,390	22,825	6,642	6,060	0,291	10,7 %	12,4 %	2930	3529,2	Transition	17 %
6,000	5,390	23,456	6,767	6,190	0,289	12,8 %	14,8 %	2750	3340,8	Transition	18 %
7,625	6,875	23,506	8,427	7,710	0,359	10,5 %	12,1 %	2740	3326,2	Transition	18 %
7,625	6,875	23,562	8,447	7,730	0,358	10,8 %	12,4 %	2730	3310,1	Transition	18 %
7,625	6,875	23,851	8,503	7,790	0,357	11,5 %	13,3 %	2650	3227,8	Transition	18 %
7,625	6,875	24,535	8,661	7,955	0,353	13,6 %	15,7 %	2480	3041,0	Transition	18 %
8,625	7,921	27,735	9,402	8,724	0,339	9,0 %	10,1 %	1850	2289,7	Transition	19 %
8,625	7,921	28,261	9,524	8,850	0,337	10,4 %	11,7 %	1760	2182,4	Transition	19 %
8,625	7,921	29,368	9,765	9,100	0,333	13,2 %	14,9 %	1600	1969,2	Transition	19 %
9,625	8,921	31,556	10,650	9,975	0,338	10,6 %	11,8 %	1340	1593,6	Elastic	16 %
11,750	11,000	32,811	12,140	11,400	0,370	3,3 %	3,6 %	1220	1414,1	Elastic	14 %
11,750	11,000	33,165	12,238	11,500	0,369	4,2 %	4,5 %	1190	1368,3	Elastic	13 %
16,000	15,010	35,454	17,089	16,125	0,482	6,8 %	7,4 %	1020	1115,5	Elastic	9 %
13,375	12,615	39,469	14,505	13,770	0,368	8,4 %	9,2 %	780	803,8	Elastic	3 %
13,375	12,615	40,167	14,681	13,950	0,366	9,8 %	10,6 %	740	762,0	Elastic	3 %
13,375	12,615	40,790	14,827	14,100	0,364	10,9 %	11,8 %	700	727,0	Elastic	4 %

Table 2-5 Collapse pressure calculations

One factor that may make it even more difficult to determine the post-expansion properties is the variation in wall thickness across the pipe cross-section. A large stress is required to expand the pipe and initial variations in wall thickness of the pipe will magnify during the expansion process. Areas with lower wall thickness will require a smaller force to be expanded and will therefore be expanded more than areas in which the wall thickness initially is higher. The result is an expanded pipe with an uneven distribution of wall thickness, which will reduce the load properties because they depend on the minimum wall thickness.

Flaws in the material may also be detrimental for the expansion process. Flaws may grow and eventually lead to fractures in the material. More stringent pipe inspection practices should be followed for pipes that are to be expanded to ensure optimum post-expansion properties.

2.5.6 Service Providers

There are three major service providers of expandable solutions: Baker Oil Tools, Enventure Global Technology, and Weatherford.

Baker Oil Tools

The EXPatch™ Expandable Cladding System is an expandable tubular, which can be used in cased-hole or open-hole applications. The cased-hole applications for the EXPatch™ include blanking off perforations to minimise water inflow in short sections and repairing damaged or corroded casing in longer sections. Combined with expandable hangers and openhole packers, the EXPatch™ can be used to reduce or shut off water inflow from reservoir zones. The system uses hydraulic force to push the cone through the pipe to expand the cladding to the inner diameter of the casing or wellbore.

Baker Oil Tools lists the following features and benefits with the EXPatch™ system (Baker Oil Tools, 2007):

- Maintain maximum ID after clad placement.
- Clad can be run in variable lengths to fit application.
- Setting mechanism does not rely on integrity of surrounding medium to place clad.
- Uses FORMlock™ technology to create anchor/seal. FORMlock™ is Baker Oil Tools' expandable liner hanger.

The linEXX™ Expandable Liner System can be used to block off sections where unexpected problems are encountered while drilling or it can be used as a part in the initial well design. The linEXX™ can be placed below a liner or casing and expanded, thus resulting in an inner diameter equal to the existing string, i.e. the system results in a monobore section. The standard running procedure for the linEXX™ system is to drill and underream the open hole below the existing casing or liner, place the linEXX™, and expand it to its final dimension using the catEXX™ hydraulic expansion system. The catEXX™ system consists of anchor, hydraulic cylinder and expansion cone. When pressure is applied to the system, slips extend and anchor the assembly in place. The pressure then extends the hydraulic cylinder and moves the cone downwards approximately 4.3 m (14 ft), thereby expanding the liner. Pressure is then bled off and the cone and slips retract. The expansion system is moved downwards and the pressurisation and de-pressurisation cycle continues until the bottom is reached. An illustration of the linEXX™ system is shown in Figure 2-26.

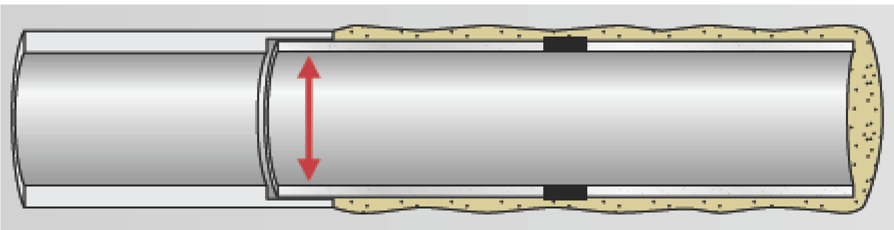

Figure 2-26 LinEXX™ system (Baker Oil Tools, 2004a)

Baker Oil Tools lists the following advantages with the linEXX™ system (Baker Oil Tools, 2004a):

- Effectively blocks off problem drilling zones without reducing casing ID as in traditional telescoping well programs.
- Applicable to cased-hole isolations of production zones.
- Can be used with isolation packers or cement to improve holding qualities.
- Top down expansion.

Baker Oil Tools also has the SealEXX™ expandable production patch system, which is an open hole formation isolation system. It is mainly used to block off water zones in open hole, but it can also be used to isolate problem zones. One application of the SealEXX™ system is shown in Figure 2-27.

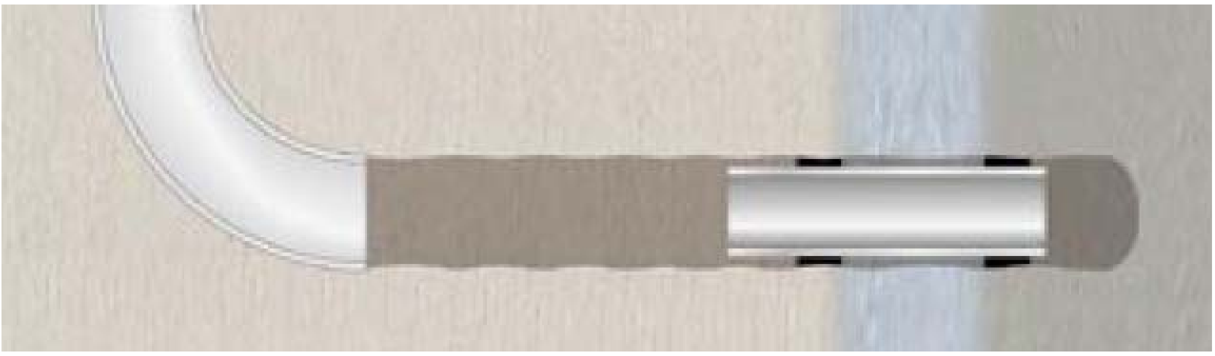

Figure 2-27 SealEXX™ expandable open hole production patch (Baker Oil Tools, 2004b)

In addition to solid expandable products, Baker Oil Tools has developed a sand screen that is expanded against the formation. The expandable sand control screen consists of a perforated base pipe with layers of filters and shroud outside. The screen may also function as a sand control screen unexpanded. The EXPress™ system combines an expandable sand control screen with solid expandables and zonal isolation. The FORMpac™ is an expandable packer which uses swelling elastomers to make a seal against the formation or casing.

Enventure Global Technology

The SET® systems include four systems: Cased-Hole system, Openhole system, Openhole Clad system, and FlexClad system.

The cased-hole system includes elastomeric bands at the top and bottom of the liner that, when expanded, anchor the system to the base pipe. The SET® Cased-Hole Systems are most often installed to seal off perforations, damaged or corroded casing, or to reinforce casing (Enventure Global Technology, 2008a).

The openhole system anchors to the bottom of an existing casing, and is then hydraulically expanded. This allows casing off the openhole while maintaining a larger hole size than what is possible with conventional technology. Some applications of the SET® Openhole System are to mitigate trouble zones, used as a part of the well design to slim down the wellbore, and extending reach. Figure 2-28 shows the installation sequences for the openhole liner system.

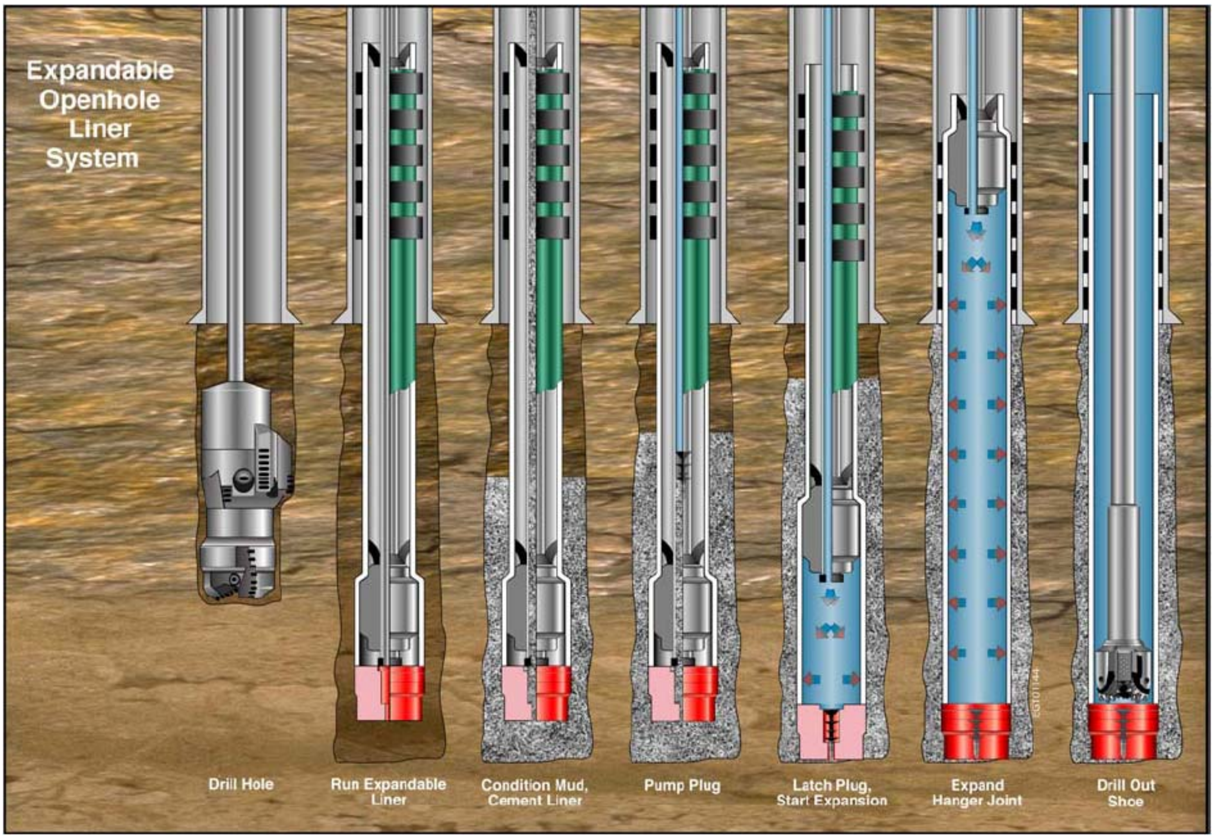

Figure 2-28 Enventure OHL installation (Enventure Global Technology, 2008c)

The openhole clad system is typically used to isolate zones. The liner with an inner work string is run into the hole, and is then expanded using hydraulic pressure to provide force from bottom. Applications include stabilizing the open hole, isolate water zones and mitigate lost circulation zones. The system has elastomer seals that seal against the formation.

The FlexClad system was primarily designed for well completions, stimulations, and workovers. This system consists of expandable joints separated by conventional API tubulars. The expandable joints use elastomeric seals that anchor and seal once expanded, whereas the API tubular are the same size as, or larger than, the post-expanded expandable joints. The cone is used to expand the expandable joints and is then pulled freely through the API tubular. The difference from the standard SET® systems is that the connections are not expanded, only the expandable joints. This makes it possible to use premium connections. The FlexClad system is typically used in cased-hole applications, but can also be used in open hole.

Weatherford

The Weatherford MetalSkin® Systems are solid expandables and feature four products: open-hole liner, monobore open-hole liner, cased-hole liner, and monobore open-hole clad. The open-hole liner and the monobore open-hole liner have similar uses; however, the monobore liner has the same size as the previous casing. When the monobore liner is used the base casing is set with an oversized shoe into which the liner is expanded. The liners are expanded bottom-up using a collapsible cone.

The cased-hole liner can be used to repair corroded or parted casing. It has elastomer seal bands for zonal isolation. The cased-hole liner does not reduce the well inner diameter as much as scab liners.

The monobore open-hole clad can be used to selectively isolate zones that are encountered during drilling without reduction in hole size. After a clad has been set, another clad can be run through it and set in the next trouble zone.

The Alternative Borehole Liner (ABL®) is an expandable slotted tubular used in the drilling phase of the well. It can be run through previous casing and expanded across the problem zone without loss of hole size.

Weatherford's ESS® is an expandable sand screen that can be compliantly expanded against the wall, thus eliminating the annular space. The expandable sand screen consists of a slotted base pipe, several layers of filters, and a protective shroud.

3 Case Study

3.1 Introduction

The standard well design on Snorre B is illustrated in Figure 3-1 and is described below:

- A 42” or 36” hole is drilled to approximately 50 meters below seabed and a 30” conductor casing is set and cemented.
- A 24” hole is drilled and an 18 5/8” surface casing is set and cemented. The final inclination of this section is maximum 45 degrees.
- A 17 ½” hole is drilled and a 13 3/8” intermediate casing is set and cemented, with a final inclination and sail angle between 40 and 80 degrees.
- A 12 ¼” hole is drilled and a 9 5/8” production liner is set and cemented above the reservoir. The 9 5/8” is set as a liner and tied back to surface because of ECD limitations.
- An 8 ½” section is drilled into the reservoir and a 7” liner is set and cemented. There is also the possibility of using a 4 ½” liner or a 5 ½” liner as a contingency.
- A 9 5/8” x 10 ¾” tieback casing is run from top down to 9 5/8” liner PBR.

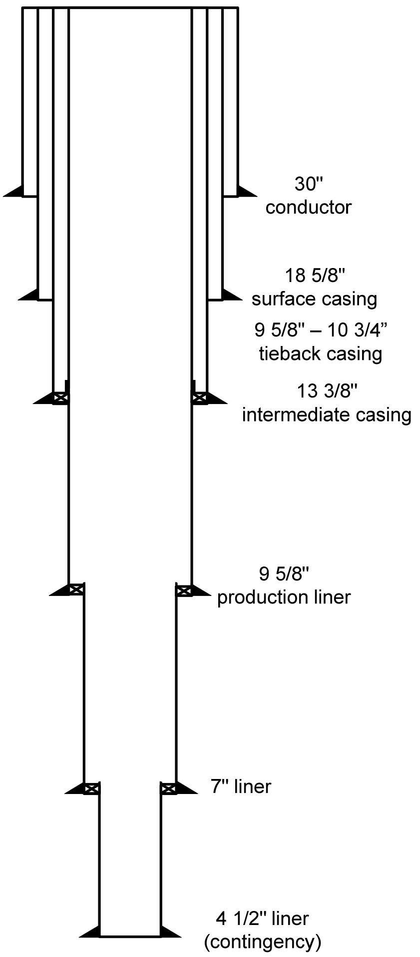

Figure 3-1 Current well design

The standard well design is based on setting a 9 5/8” liner in the cap rock above the reservoir. The liner is cemented before drilling is continued into the reservoir. The cement job is critical here because the cement is important for the integrity of the well. The reservoir section is then drilled with an 8 ½” bit before a 7” liner is set and cemented. The cement job is also important in this section to ensure good zonal isolation. Proper zonal isolation is needed because the wells are completed with intelligent well systems.

Well conditions or reservoir conditions determine whether the contingency needs to be used or not. The contingency liner may be used if reservoir conditions, such as pore pressure and fracturing pressure, dictate that a zone has to be cased off before drilling can be continued. Another reason for using the contingency liner is the length of the reservoir section. If the reservoir section is too long, the cement job is likely to fail because cementing such long horizontal sections is difficult. By using the contingency liner, the section can be split in two, which may make it easier to get a good cement job. If the reservoir needs to be drilled in two sections, the hole size is decreased if conventional technology is used. If the contingency well design is used, it does not give the possibility of having an intelligent well completion in the last section because of size limitations. The intelligent well completion system used in these wells requires a 6.1” inner diameter.

A typical well has a long horizontal section through the reservoir and goes through several reservoir zones, as shown in Figure 3-2. An intelligent well completion with inflow control valves and isolation packers are used to selectively produce from, or inject into, each of the zones.

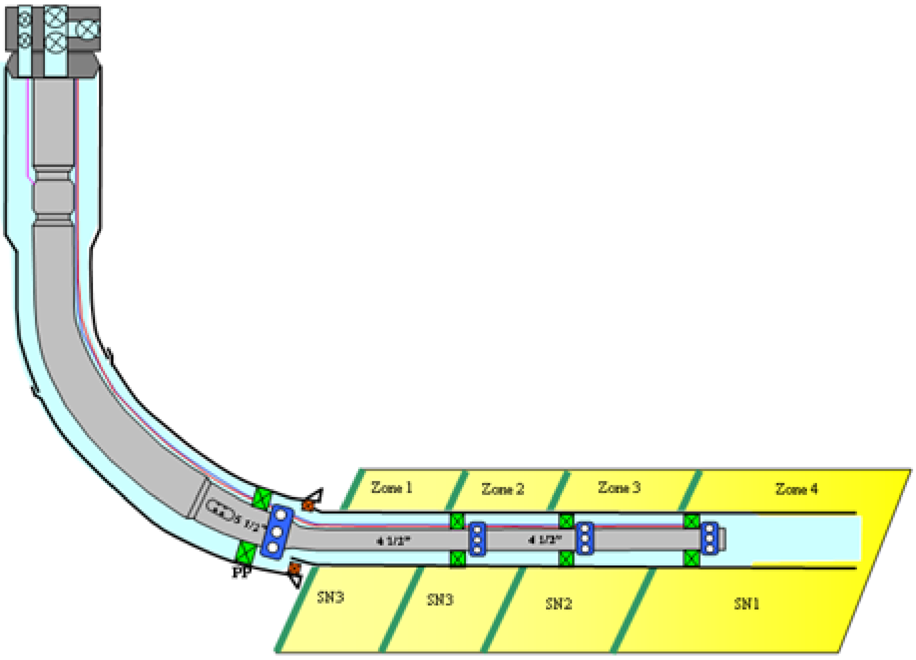

Figure 3-2 Well completion for a typical Snorre well

3.2 Relevant Case Histories

3.2.1 Gulf of Mexico – First Commercial use of SET® Technology

Dupal et al. (2001) describes a case history in the Gulf of Mexico where the first commercial installation of Enventure's solid expandable technology was done in November 1999. The objective was to lower cost by decreasing casing and hole sizes compared to conventional technology. Halliburton Energy Services' Integrated Solutions group was the lead contractor for Chevron USA Production Company on a well in the West Cameron Block 17 field, where solid expandable technology was used to reach the objective. The conventional and the expandable well plan are shown in Figure 3-3.

The standard casing design in this field consisted of 9 5/8" 53.5 pounds per foot (ppf) casing joints. In the case where a 7 5/8" x 9 5/8" expandable liner was to be set, the bottom four joints of the 9 5/8" casing were 47.0 ppf to allow for a larger inner diameter. The wellbore below the 9 5/8" casing were slightly enlarged to 9 7/8" diameter to allow for sufficient cement volume and annular clearance to expand the liner. The cement volume was planned so that the top of cement would be at the bottom of the base casing after the liner had been expanded. To achieve this, the hole interval was logged with a caliper to accurately determine the cement volumes necessary.

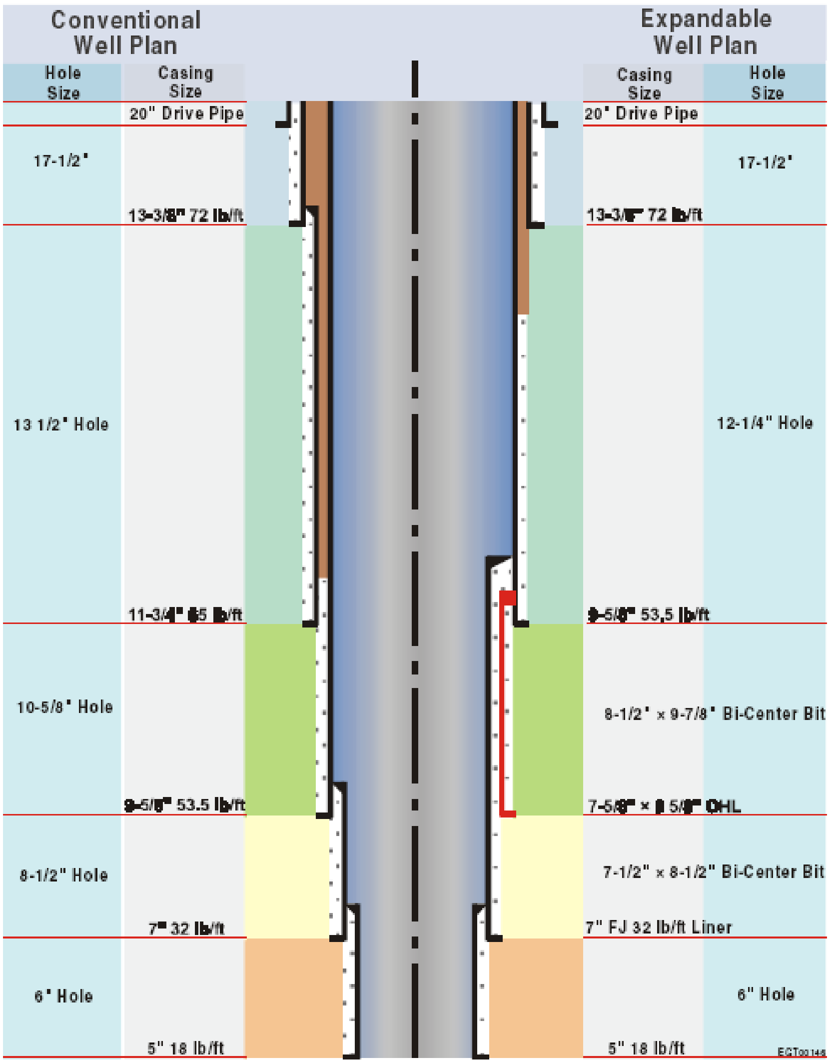

Figure 3-3 Conventional and expandable well plan for GOM case history (Dupal et al., 2001)

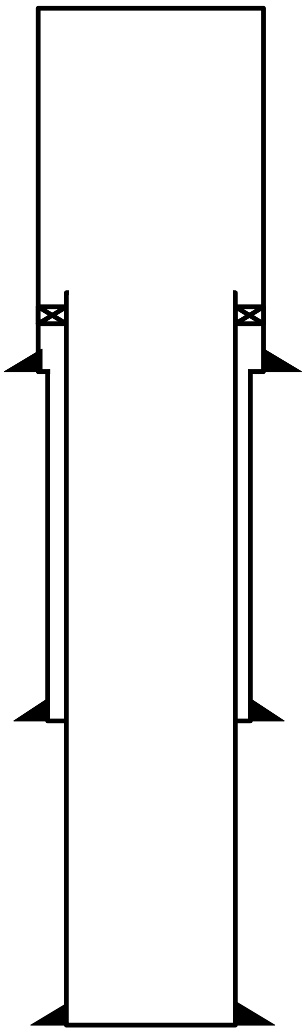

Figure 3-4 Relevant part of casing design for Gulf of Mexico case history

A 300 m (985 ft) 7 5/8” x 9 5/8” solid expandable liner was run to 4,002 m (13,131 ft) depth on a 3 ½” x 5” tapered inner string. The well was circulated, the cement pumped, and the latchdown plug dropped. Once the latchdown plug landed, the expansion process took about 4 ½ hours. Pressure observed in the expansion process was 4,000 psi in average, and 4,800 psi maximum when the hanger joint expanded against the base casing. The liner shortened from 300 m to 288 m (946 ft) in the expansion process. The top of the liner was then at 3,714 m (12,185 ft) depth.

After the liner had been set, the mill assembly was run into the well and mud weight was reduced to provide a 149 bar (2,165 psi) negative differential (collapse) test of the liner. The negative test was followed by a 241 bar (3,500 psi) positive pressure (burst) test of the liner. The shoe track was milled out and an 8 ½” enlarged hole was drilled through the depleted sands and a conventional 7” production liner with flush joints was run. The top of the production liner was set above the top of the expanded liner because anticipated loads exceeded the load properties of the expanded liner.

The well was then drilled to target depth and all objectives were met.

3.2.2 The Yibal Field in Oman – Expandable OHC and OHL with Swelling Elastomers

An expandable open-hole clad and open-hole liner with swelling elastomers was installed in the Yibal field in Oman (Al-Balushi, Al-Rashdi, Al-Shandoodi, & Vannoort, 2004). The larger inner diameter offered by the expandable solutions gave the opportunity to run a larger outer diameter smart completion to control the flow from the different perforation zones.

The wells in the Yibal field has for a long time been completed with cemented liners and selective perforations, however, there are several disadvantages with using this method in this field, such as failing to get a good cement job and thereby failing to achieve selective perforations. The wells in this field were often drilled vertical, but it was decided that two horizontal wells should replace five vertical wells. The horizontal wells were to be completed with solid expandable tubulars coated with external elastomeric seals.

The proposed well had an approximately 1000 m horizontal section through the reservoir, and were to be completed with 1000 m solid expandable tubulars with swelling elastomers. The SET® and elastomers were intended to isolate fractures from the wellbore.

The well design for a typical horizontal well in the Yibal field has a 20” surface casing, a 13 3/8” intermediate casing, a 9 5/8” production casing, a 7” production liner, and a 6 1/8” horizontal hole section. The last horizontal section is conventionally completed barefoot or with a cemented 4 ½” liner. In the proposed well a 5 ½” SET® with swelling elastomers is used in the last section. The reservoir fluid is then produced using an electrical submersible pump (ESP).

It was planned to complete the horizontal section with three sections of SET® with elastomers, where the lengths are 250 m, 250 m and 500 m, however, the hole condition after each installation should be assessed and plan adjusted accordingly. Running the SET® in shorter sections allows more elastomers per section because of lower friction; however, there will be gaps between the sections and these gaps may be in a part of the formation with fractures or water bearing zones.

The top sections of the well were drilled according to plan, and the 7” liner was set at 1,584 m, which cased off the troublesome shale. The horizontal section was then drilled with a 6 1/8” bit and a mud motor. Some intervals with high dog leg severity (DLS) were observed, but these were cleared while tripping out of hole and during a drift run prior to running the SET® with elastomers. The well was then logged to identify faults and fractures, and reservoir pressures along the horizontal section. A caliper log was also run to measure the hole size to determine the necessary thickness of the elastomers to obtain a seal against the formation.

The well was planned to be completed with four perforation intervals, each replacing the production of a vertical well.

After evaluating the logs, the SET® section lengths were modified to 305 m, 385 m and 296 m in order to locate the open hole gaps in the perforation zones. The modified plan is shown in Figure 3-5.

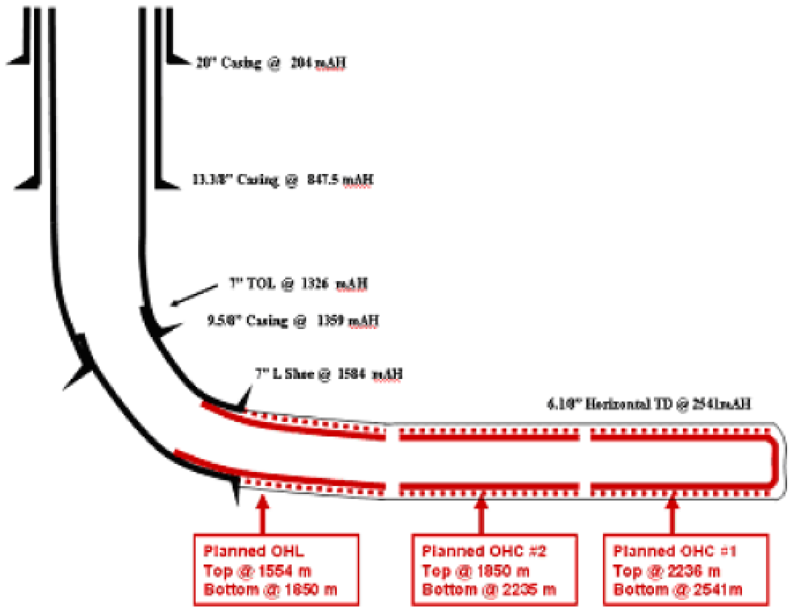

Figure 3-5 Adjusted SET® completion after log evaluation (Al-Balushi et al., 2004)

The first SET® OHC length run in hole was 315 m, which was reduced in length to 305 m post expansion. The SET® was pressurised and expansion started. An overpressure was observed at the seals, which indicated that there was a good compression force acting on the elastomers into the formation. After this successful run, which was a world record in it being the longest OHC with swelling elastomers, it was decided to run a 708 m OHL with swelling elastomers. The OHL length reduced to 686 m post expansion. The thickness of the elastomers were 5.5 mm in the majority of the OHL, but was reduced to 4 mm in the top 100 m because of torque and drag simulations. The OHL was run in hole to the planned depth without major drag being observed. The SET® completion actually installed is shown in Figure 3-6. The inner diameter for the SET® was 5.46". After milling out the OHL shoe and running a casing collar log to confirm the elastomer locations, the SET® was perforated in the four intervals planned.

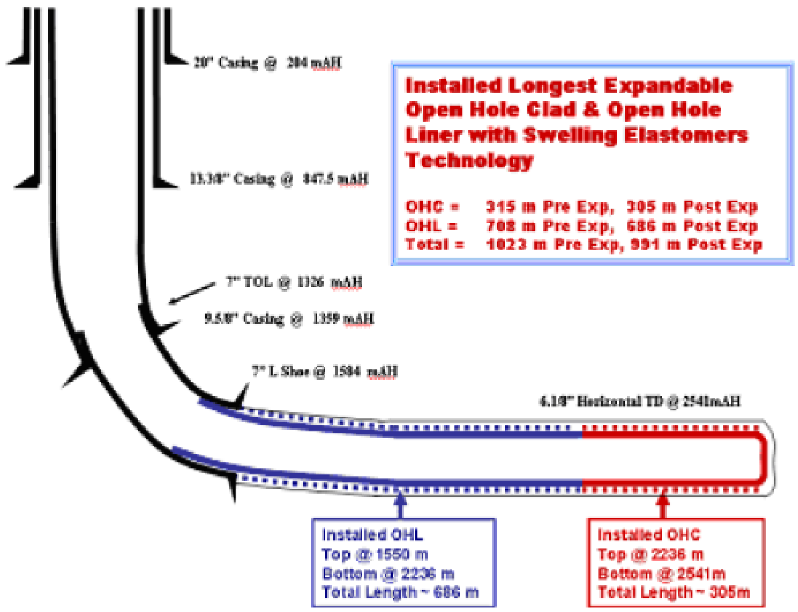

Figure 3-6 SET® completion installed in the Yibal field (Al-Balushi et al., 2004)

The SET® installations were considered a success and the well were completed within the planned time and cost.

3.2.3 South Texas – Monodiameter Prototype

Campo et al. (2004) describes the principle of Enventure's solution to monobore drilling liners. The prototype was based on using a cone in a cone launcher at the bottom of the expandable liner. Since the cone is situated in the cone launcher, which has to be able to pass through the base casing, the monodiameter process required two passes with different size cones. One bottom-up expansion and then a top-down expansion was performed.

An 11 ¾", 60 ppf, P-110 casing was set and used as a base casing for the expandable liner. A 10 5/8" hole was drilled approximately 300 ft and underreamed to 12 ¼". The first 9 5/8" expandable liner was run in hole and expanded bottom-up to a 9.9" ID. The shoe was then drilled out to create a rathole before expanding the liner top-down to 10.4" ID. The top-down cone was mainly mechanically driven with drill collar weight, but to provide an additional force to expand the overlap where there were elastomers for sealing, the pipe rams were closed and pressure applied below the BOP to provide a hydraulic force.

Drilling was then continued with a 9 7/8" bit and the hole was underreamed to 12 ¼". Approximately 300 ft was drilled in this section too. A second monodiameter liner was run and expanded in two passes to an ultimate ID of 10.4". Both monobore liners and overlaps were successfully tested to 4000 psi.

In the scenario described, an 11 ¾” base casing is set, followed by installation of a 9 5/8” expandable drilling liner. The 9 5/8” drilling liner is expanded, as well as the 11 ¾” base casing overlap. The post-expansion ID in the expandable liner is 10.4”; however, this is less than the inner diameter of the base casing. Additional monobore liners can be run and expanded to continue the 10.4” ID. Expanding the overlap is a limiting factor because the expansion ratio is higher here than in the rest of the drilling liner. According to Campo et al. (2004) the pipe material available can only withstand an expansion ratio of 30 %. In the example of expanding a 9 5/8” drilling liner, the expansion ratio is 17 % for the drilling liner and 24 % for the base casing overlap. A 9 5/8” production liner is installed through the monobore drilling liner prior to completion to provide well integrity.

The smaller the diameter of the liner is, the higher the expansion ratio must be to create a monodiameter section. For a 7 5/8” expandable liner that is expanded into a 9 5/8” base casing to 8.0” ID, the expansion ratio for the liner is 19 % while the base casing overlap expands 29 %, which is close to the expansion limit for current material technology. The post-expansion ID for the expandable liner is 8.0”. It should be noted that the inner diameter of the expandable liner in these cases are not the same as for the base casing, but additional expandable casings of the same size can be run through it, allowing long sections of the same size casing to be run. The monodiameter liners were expanded two times, which is a time consuming process. The expansion process should be improved, but it was used in this concept trial to show that multiple monodiameter liners can be installed.

3.2.4 Arkoma, Oklahoma, USA – First Deployment of a Monobore Liner Extension

The world’s first installation of a true monobore expandable liner extension system in a commercial well was in BP’s Arkoma field in southeast Oklahoma, USA (Stockmeyer, Adam, Emerson, Baker, & Coolidge, 2007; Stockmeyer, Storey, & Emerson, 2008). The system used here was Baker Oil Tools’ linEXX™, which uses a recess shoe at the bottom of the base casing.

The recess shoe had previously been used as a contingency solution in several wells in the North Sea in case well problems should occur during drilling the reservoir section, but the liner itself was not needed in these wells. The system can also be used as a basis of design, where the technology provides the option of beginning the well with a smaller casing size for reduced costs.

The wells in which the system was developed were in the Kristin and Kvitebjørn fields in the Norwegian sector of the North Sea where pressures and temperatures are considered HPHT with 900 bar bottomhole pressure and 170 °C bottomhole temperature respectively. These values were used as a design basis for the expandable monobore liner system.

Two recess shoes sizes (OD) are available: one if the liner is to be cemented and one for non-cemented expandable liner. The recess shoe that allows circulation for the post-expanded liner is 11.25” OD and the open hole section below needs to be reamed to 10.25” if the liner is to be cemented. The cement job is performed post expansion. The recess shoe that does not provide the possibility of circulation for the post-expanded liner is 10.166” OD and the open hole section below needs to be reamed to 9.50” to allow the liner to be expanded and for open hole packers for zonal isolation.

The carbon-manganese, low-alloy steel used in the expandable casing has a minimum yield strength of 70 ksi. The work hardening process in which the casing is expanded leads to an increase in tensile strength and hardness. The pre-expanded casing has a hardness of approximately 90 HRB, which increases to 28 HRC at the ID and 21 HRC at the OD post expansion. The reason for the difference in ID and OD hardness is because the expansion ratio is different. The expansion process leads to an ID expansion of 18 % (7.310” to 8.625”) and an OD expansion of 15.5 % (8.000” to 9.240”).

Prior to the first commercial application, there were performed several trials. Two trials resulted in split casing. A split casing, and a following fishing operation, in the field trial would have resulted in increased time spent and thereby increasing the cost. To reduce the risk of extended time required, the pipe diameter of the pre-expanded casing was increased to 8.0” OD, quality assurance was enhanced, and fishing services were on stand-by. In addition, wellhead selection was done to allow for the entire casing, both the 9 5/8” base casing and the expanded 8.0”, to be pulled out of the hole if problems were encountered with the post-expanded pipe. The expanded pipe has an 8 ½” drift. Figure 3-7 shows the current casing design and the optimised casing design with the monobore liner extension.

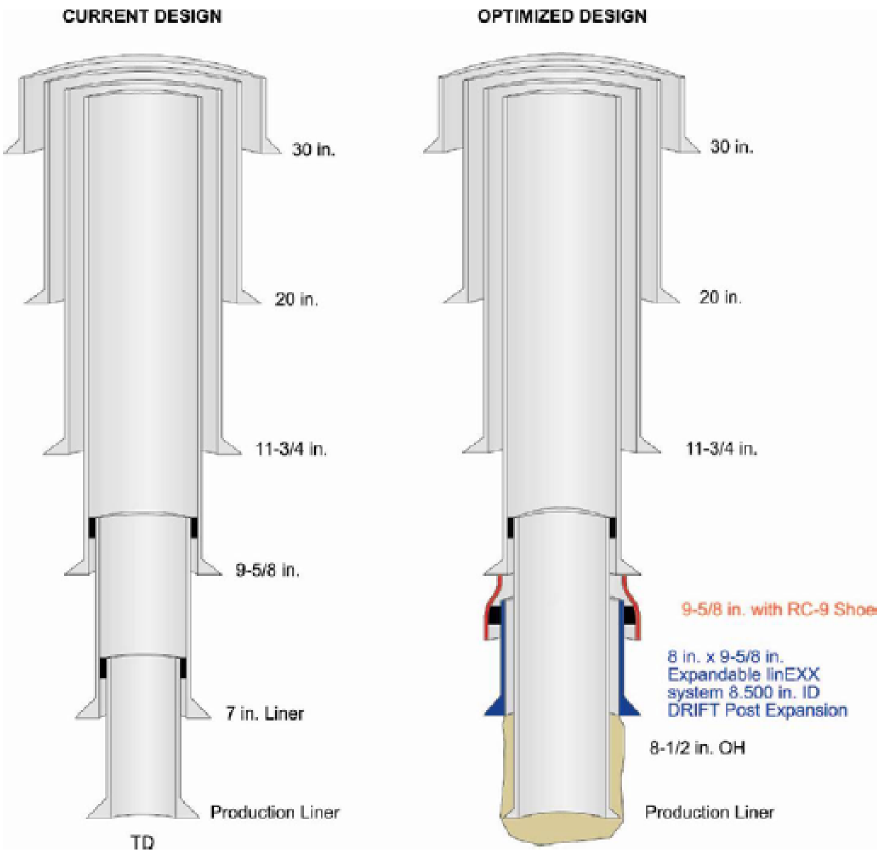

Figure 3-7 Casing designs, Arkoma (Stockmeyer et al., 2007)

In the field trial a 12 3/8” vertical hole was air-drilled to approximately 1250 m. The 9 5/8” base casing and recess shoe were run to a depth of 789 m. The base casing was not cemented in place to allow for contingency removal, if needed. The expandable liner (461 m) and the expandable liner hanger/packer were run in hole. The liner hanger and liner were expanded using a top-down system. The liner was expanded 18 % to 8.625” nominal ID and 8 ½” drift ID in 4.3 m (14 ft) increments.

After expanding the entire liner, the expansion assembly was retrieved and a drift run was performed to verify drift ID. A cement retainer was set and the liner was cemented in place, with the cement volume calculated such that there was no cement return into the base casing through the recess shoe ports. The liner was then successfully pressure tested and the cement retainer and excess cement drilled out. Drilling continued below the expanded liner to TD. The expanded liner was isolated with the production casing before completing the well.

3.3 The Snorre Field

To be able to reach the reservoir with a larger size than the contingency solution offers, expandable technology may be a solution.

To change the casing design in the reservoir sections, assuming that the entire hole needs to be cased off, there are basically two different solutions that may be applied. One option is to expand the liner set in the first reservoir section. In this case this means that the 9 5/8", or equivalent size, production liner is set, a hole is drilled and underreamed, and an expandable liner is run and expanded below the production liner. The second reservoir section can then be drilled with a larger bit size than in the contingency well design where a 6" hole is drilled.

Another option may be to set the 7" liner according to the standard well design, and expand the next liner in the last section of the reservoir, thus giving a larger hole at the target depth. A review of the products that the service providers offers excluded the second option in this particular case, mainly because of the inner diameter requirement. A liner that is expanded to 7" is typically run as a 5 ½" liner. The post-expansion inner diameter is as Table 3-1 shows then lower than what is required due to the smart well equipment.

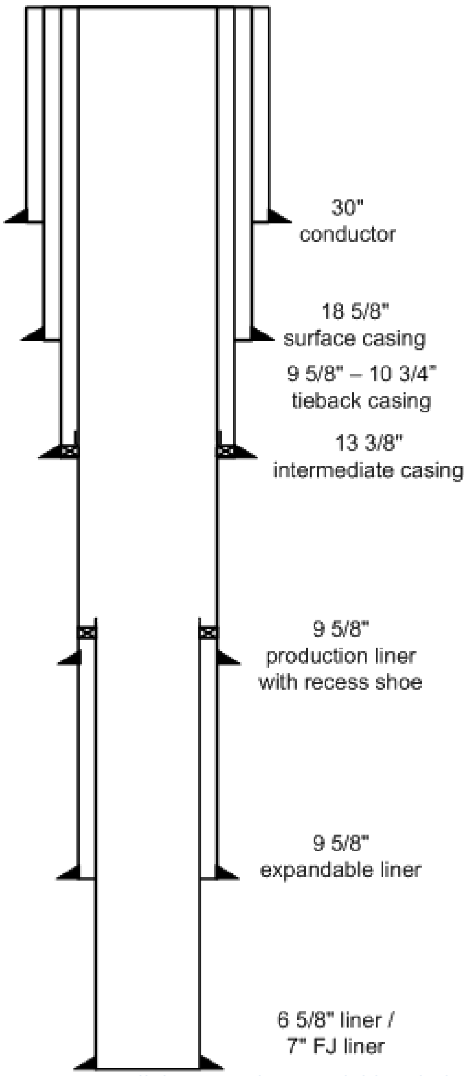

Figure 3-8 Well design with expandable tubular, option 1

Figure 3-8 shows one option for using expandable technology to limit the reduction in hole size. If the current casing design is to be used above the reservoir sections, a 9 5/8" production liner is set and cemented to provide sufficient well integrity. The next section, which is the first reservoir section, is then set using an expandable liner. Table 3-1 shows the specifications for some of Enventure's SET® products. The SET® that is relevant in this case has an OD of 7 5/8" and has a drift ID of 7.633" after expansion, whereas the base casing has a drift ID of 8.379". This is a 9 % decrease in inner diameter, which may make it difficult to run the same liner as if it had been monobore. A 6 5/8" liner can then be run through the expanded liner, however, this does not have a large enough inner diameter for the intelligent well system components. The 7 5/8" x 9 5/8" expandable liner was used in a well in the Gulf of Mexico (see chapter 3.2.1), where the well construction challenges was similar to that in the Snorre field. In this case, a production liner had to be set through the entire expanded liner because of the load properties of the expanded liner was not sufficient. A 7" production liner with flush joints was then used, which would enable the use of an intelligent well completion.

System size	Base Casing				Solid Expandable Tubular System									API	
SET x Base Casing	OD (in.)	Weight (lb/ft)	ID (in.)	Drift (in.)	Pre-Expansion			Initial Wall (in.)	Launcher OD (in.)	Post-Expansion			Exp. Ratio (ID)	Yield (psi)	Collapse (psi)
					OD (in.)	ID (in.)	Wt (lb/ft)			OD (in.)	ID (in.)	Drift (in.)			
8.625 32.0 lb/ft x 10.750 65.7 lb/ft	10.750	65.7	9.560	9.404	8.625	7.921	32.0	0.352	9.404	9.402	8.724	8.637	10.1 %	5200	1850
7.625 29.7 lb/ft x 9.625 53.5 lb/ft	9.625	53.5	8.535	8.379	7.625	6.875	29.7	0.375	8.379	8.427	7.710	7.633	12.1 %	6130	2740
5.500 17.0 lb/ft x 7.000 26.0 lb/ft	7.000	26.0	6.276	6.151	5.500	4.892	17.0	0.304	6.151	6.147	5.570	5.511	13.9 %	6770	3390

Table 3-1 Enventure SET® specifications example

The clearance between the expandable liner and the 7” production liner is quite narrow in this case and may lead to increased torque and drag, as well as difficulties in running it to the planned depth. A larger base casing can be used to avoid this. A 10 ¾” production liner can be set and cemented in the cap rock above the reservoir instead of the 9 5/8” that is used in the standard well design today. We see from Table 3-1 that the inner diameter of the post-expanded liner is 8.724”, which is a bit larger than the ID of a standard 9 5/8” liner which is 8.535”. A 7” liner should be easier to run since the clearance is higher.

Baker Oil Tools has a product for monobore liner extension, the linEXX™ system, and this was the first monobore system that was commercially deployed, see chapter 3.2.4. This is a slightly different system than Enventure’s system. The linEXX™ system uses an oversized shoe, called recess shoe, on the base casing. The liner is expanded into the recess shoe to avoid a reduction in ID. The recess shoes have been installed several times in North Sea wells; however, they have only been used as a contingency. The liner itself has not been run in these wells because it has not been necessary to use the contingency. In September 2006 it was however installed in a well in Oklahoma, USA. In this case the base casing was 9 5/8” and the expandable liner was 8” OD pre-expansion, with an 8 ½” drift post-expansion. The post-expansion drift is large enough for a 7“ liner to be run through it, which allows the intelligent well system components.

Another solution may be to use a similar well design as in the Yibal field, see chapter 3.2.2. The operator planned to install three open hole clads, but actually one open hole clad and one open hole liner was installed in an approximately 1,000 m horizontal section. The expandable products used in the Yibal field used elastomers for zonal isolation, and provided a larger ID than a regular liner would. The clad and liner were perforated in four intervals, each replacing the production from a vertical well.

The actual products used in the Yibal field gives a 5.46” ID, which is not enough for the intelligent well system used on the Snorre field, however, the same concept only larger dimensions could be used to give the necessary ID.

An expandable liner can also be used above the reservoir. An expandable liner can be expanded from the 13 3/8” intermediate casing and set at the top of the reservoir, where the 9 5/8” is set in the standard casing design. The first section in the reservoir can then be drilled with a 12 ¼" bit and a 9 5/8" liner set. The 9 5/8" liner hanger may have to be set above the expandable casing since the post-expanded pipe properties may be too low for production loads. The last section in the reservoir can be drilled with an 8 ½" bit and a 7" liner set, which has a large enough ID to allow for the installation of intelligent well system components.

To illustrate whether an expandable casing can be a viable solution in this specific field, a casing design will be performed for two options, in which actual data from a well is used.

Table 3-2 shows the casing scheme for the original well, which is according to the contingency casing design on Snorre B.

OD (in)	Name	Type	Hole size (in)	Measured depths (m)			Mud at shoe (sg)
				Hanger	Shoe	TOC	
30	Conductor	Casing	36	384	433	384	1.030
18 5/8	Surface	Casing	24	384	1350	384	1.350
13 3/8	Intermediate	Casing	17 ½	384	2880	2580	1.510
9 5/8	Production	Liner	12 ¼	2830	4635	4035	1.580
7	Production	Liner	8 ½	4585	5900	4585	1.510
4 ½	Production	Liner	6	5850	6699	5850	1.460
9 5/8	Production	Tieback		384	2830	2830	1.100

Table 3-2 Casing scheme, original well

The expandable liner gets reduced collapse strength after expansion. It is therefore not strong enough to be a production liner, which means that the 7" liner needs to extend from the base casing. Therefore, when doing casing design on the expandable liner, only drilling loads need to be taken into consideration, not production loads. In addition to collapse issues, the connections are not gas tight, which is also a reason why the expandable liners are not qualified as barrier elements.

The casing design criteria has been used according to StatoilHydro requirements (Østebø, 2006). Since a large part of the well remains unchanged, only casing design for the relevant section will be done, which means only the expandable liner and the subsequent production liner that covers it.

Burst loads in drilling include displacement to gas and pressure test. In the displacement to gas scenario, the well is shut in at wellhead (BOP) after a kick. The entire wellbore is filled with gas in this case. The pressure in the well is equal to the pore pressure at the influx depth minus the gas gradient. The pressure is also limited by the fracturing pressure at the casing shoe. If the pressure exceeds the fracturing pressure, the pressure in the well above this point will be the fracturing pressure minus the gas gradient. The pressure test should have a surface pressure such that the casing is tested to maximum expected differential pressure.

Collapse loads in drilling include cementing and lost returns with mud drop. Just after the cement has been displaced there is displacement fluid inside the liner and cement outside. The difference in density results in a differential pressure, which may collapse the liner. When drilling the next section, lost circulation situations may cause the mud level to drop. If such a zone is encountered, the mud will drop to balance the lowest pore pressure in open hole. This results in a decrease in internal pressure. The fluid on the outside of the liner is assumed to have the density of the mud used on the section. The lost returns with mud drop scenario are to be used for strings to be drilled out when lost circulation is anticipated. The mud level drop can be reduced to a minimum of 250 m if drilling in formations where experience from nearby wells show insignificant lost circulation situations or if the loss-zone has a low permeability.

Casing design has been performed in StressCheck. Input to the program has been expected pore pressure and fracturing pressure from an actual well, temperature profile, well path, casing setting depths, cement heights, and mud and cement properties. The input for both scenarios has been the same; the only difference is the casing scheme. The burst and collapse pressures of the expandable liners are based on API formulas and the post expansion properties.

Similar lengths of the reservoir sections as in the original well have been used in the casing designs; however, it should be noted that the lengths of expandable liner that may be needed in this casing design is longer than what usually is run today. The length of the expandable liner used in these casing designs is used to illustrate what future enhancements may enable.

3.4 Casing Design - linEXX™

The first scenario which will be investigated is to use the expandable casing in the first section of the reservoir, a similar solution to what was done in Arkoma (see chapter 3.2.4) and what is currently the contingency solution for several fields in the North Sea.

The base casing is a 9 5/8" production liner which is set and cemented with a recess shoe in the cap rock above the reservoir. The next hole section is drilled with a 8 ½" bit and underreamed until a casing has to be set to isolate the formation. The expandable liner is then run and expanded to the same inner diameter as the base casing. To achieve zonal isolation, the liner can be cemented or it can be run with elastomers that expand with the liner and seal against the formation. The second reservoir section is then drilled with an 8 ½" bit to the target depth and a 7" liner is set from the 9 5/8" base casing to bottom to isolate the weaker expandable liner.

Table 3-3 shows the casing scheme for the proposed well where the contingency liner is not used and an expandable liner is used in the first reservoir section.

OD (in)	Name	Type	Hole size (in)	Measured depths (m)			Mud at shoe (sg)
				Hanger	Shoe	TOC	
30	Conductor	Casing	36	384	433	384	1.030
18 5/8	Surface	Casing	24	384	1350	384	1.350
13 3/8	Intermediate	Casing	17 ½	384	2880	2580	1.510
9 5/8	Production	Liner	12 ¼	2830	4635	4035	1.580
9 5/8	Drilling liner	Expandable	12 ¼	4635	5700	4635	1.510
7	Production	Liner	8 ½	4585	6699	4585	1.460
9 5/8	Production	Tieback		384	2830	2830	1.100

Table 3-3 Casing scheme first scenario

Figure A-1 in appendix A shows the well schematic with depths of setting points and top of cement, corresponding to the values in Table 3-3.

Figure A-2 shows a plot of pore pressure gradients and fracture gradients along the well path as well as the mud weight used at the casing setting depths. The plot shows that there is potentially a high pressure zone at approximately 5700 mMD which may have to be cased off.

The burst loads for the first reservoir section includes displacement to gas, pressure test and green cement pressure test. Figures A-3 and A-4 shows the plots for the burst scenarios for the 9 5/8" section, including both the base casing and the expandable liner. The expandable liner is the limiting factor in the casing design since the load properties is lower than the base casing. The base casing is classified as a production casing, but the expandable liner is used as a drilling liner and cased off afterwards.

The displacement to gas scenario gives the lowest differential pressures and the pressure tests are therefore the design loads for this casing section. The influx depth of gas is at the bottom of the well at 6699 mMD, and the gas density used is 0.6 s.g. These values give the graphs shown in the burst plots. The green cement pressure test, which is a pressure test of the casing immediately after bumping the cement plug, is done with a surface test pressure of 305 bar with 1.51 s.g. mud in the casing and 1.90 s.g. cement outside. The pressure test is performed when the last reservoir section has been drilled and the plot shows a pressure test with 185 bar surface pressure and 1.46 s.g. mud in well. The surface test pressures are approximately the maximum pressures that the expandable casing can be tested to in order to have the required safety factor of 1.1. The liner in the first reservoir section is usually tested to higher pressures than this; however, since the expandable liner in this case is not going to be exposed to production loads, the pressure tests here should be sufficient. Figure A-5 shows the burst design for the 9 5/8" section. The lines almost coincide at the expandable liner, which is because of the test pressures selected.

The collapse loads for the first reservoir section where the expandable liner is set is cementing and partial evacuation. Figures A-6 and A-7 shows the collapse plots for the two scenarios in the 9 5/8" section. The input to the cementing scenario is top of cement, which is 4035 mMD, slurry density, which is 1.90 s.g., and the displacement fluid density, which is 1.51 s.g. These values give the graph shown in the figures. The full/partial evacuation scenario is based on mud level drop of 250 mMD, which is the limiting scenario in this case. If lost circulation zones are not likely to be encountered, the requirements state that the minimum mud level drop that the liner shall be designed for is 250 mMD. If the mud level drops more than 500 mMD, the safety factor for collapse of the expandable liner is below what is required. The required safety factor for collapse is 1.1. The full/partial evacuation scenario is the design load for collapse of this section as shown in Figure A-8. This design should then be sufficient if lost circulation zones do not cause the mud level to drop more than 500 mMD.

Figures A-9 , A-10 and A-11 show collapse plots for the same section, but these include the scenario lost returns with mud drop. The lost returns depth is 6699 mMD, which has a pore pressure of 275.55 bar. This gives a mud level drop of 684.6 m, which may cause the expandable liner to collapse.

Figures A-12 to A-17 shows the burst and collapse plots for the 7" liner. The 7" liner is classified as a production casing and both drilling loads and production loads needs to be taken into consideration in the casing design.

Burst load in the drilling process for the production liner is the pressure tests. The pressure test and the green cement pressure test are shown in the plots with 400 bar surface pressure. Since this liner is not going to be drilled out of displacement to gas does not need to be included. Production loads for burst design includes tubing leak and stimulation surface leak, which describes a leak in the tubing just below the wellhead during production and injection, respectively.

Collapse load in the drilling process for the production liner is cementing and during production the collapse load is above/below packer, which describes a leakage across the production packer.

3.5 Casing Design - Enventure SET®

The second scenario is based on changing a part of the current well design above the reservoir as well as in the reservoir. A 10 ¾" liner will replace the 9 5/8" liner that is used in the standard well design. This is done to give a larger clearance for running a 7" liner through the expandable casing afterwards. An expandable liner is run and expanded below the 10 ¾" liner in the first section of the reservoir.

OD (in)	Name	Type	Hole size (in)	Measured depths (m)			Mud at shoe (sg)
				Hanger	Shoe	TOC	
30	Conductor	Casing	36	384	433	384	1.030
18 5/8	Surface	Casing	24	384	1350	384	1.350
13 3/8	Intermediate	Casing	17 ½	384	2880	2580	1.510
10 ¾	Production	Liner	12 ¼	2830	4635	4035	1.580
10 ¾	Drilling liner	Expandable	12 ¼	4635	5700	4635	1.510
7	Production	Liner	8 ½	4585	6699	4585	1.460
10 ¾	Production	Tieback		384	2830	2830	1.100

Table 3-4 Casing scheme second scenario

Figure B-1 in appendix B shows the well schematic with depths of setting points and top of cement, corresponding to the values in Table 3-4.

Figure B-2 shows a plot of pore pressure gradients and fracture gradients along the well path as well as the mud weight used at the casing setting depths. The values are equal to the values used in the first casing design to be able to compare.

The burst loads for the first reservoir section include displacement to gas, pressure test, and green cement pressure test. Figures B-3 and B-4 show the plots for the burst scenarios for the 10 ¾" section, including both the base casing and the expandable liner. The expandable liner is the limiting factor in the casing design since the load properties are lower than the base casing. The base casing is classified as a production casing and additional load scenarios have to be considered for this section, but the expandable liner is used as a drilling liner and cased off afterwards.

The design load for this section is pressure testing. The displacement to gas scenario gives a lower load than the pressure tests. The influx depth of gas is at the bottom of the well at 6699 mMD, and the gas density used is 0.6 s.g. The surface pressure for the pressure tests are the same as for the casing design in the first scenario. These values give the graphs shown in the burst plots in Appendix B. The green cement pressure test is shown with a surface test pressure of 305 bar with 1.51 s.g. mud in the casing and 1.90 s.g. cement outside. The pressure test is done when the last liner has been set and cemented in place and the plot shows a pressure test with 185 bar surface pressure and 1.46 s.g. mud in well. Figure B-5 shows the burst design for the 10 ¾" section.

The collapse loads for the first reservoir section, where the expandable liner is set, is cementing and partial evacuation. Figures B-6 and B-7 show the collapse plots for the two scenarios in the 10 ¾" section. The input to the cementing scenario is top of cement, which is 4035 mMD, slurry density, which is 1.90 s.g., and the displacement fluid density, which is 1.51 s.g. These values give the graph shown in the figures. The full/partial evacuation scenario is based on mud level drop of 250 mMD, which is the minimum requirement if lost circulation zones are not likely to be encountered. The maximum mud drop for this case is 490 m. If the mud level drops more than this, the safety factor for collapse of the expandable liner is below what is required, which is 1.1.

Figures B-9 , B-10 and B-11 show collapse plots for the same section, but these include the scenario lost returns with mud drop. If this scenario is included the expandable liner does not have high enough collapse strength and may collapse. The mud level drop is 684.6 mMD, which is higher than the calculated maximum value of 490 mMD.

The casing design for the 7” production liner that is run through the expandable liner is identical as the first casing design because the input values are equal.

4 Discussion

The drainage strategy for the Snorre field is based on long horizontal producers with commingled production from several reservoir zones. The difference in permeabilities leads to rapid water and gas breakthrough. Intelligent well completion systems are used to ensure optimum sweep efficiency and it provides the ability to control inflow from the different reservoir zones and monitoring of downhole parameters such as pressure and temperature. These systems enable monitoring, remote choking, or shutting off zones with poor performance without intervention. Zone control is one of the major methods for increased oil recovery on the Snorre field. The intelligent well system requires a minimum casing ID which makes it necessary to consider this in the casing design.

The Snorre reservoir consists of several zones with pressure barriers in between. Some of the zones are depleted while some have the initial pore pressure. This makes drilling through the reservoir difficult as the mud window may be quite narrow. As demonstrated in the theory section of this thesis, the fracturing pressure decreases when the pore pressure decreases. When drilling, the well pressure needs to be between the pore pressure and the fracturing pressure in the entire open hole section, i.e. from one casing shoe until a new casing is set. The pore pressure and the fracturing pressure distribution in the reservoir may make it necessary to case off a part of the reservoir earlier than planned before drilling can be continued. Using conventional technology this means a reduction in diameter, which may cause parts of the reservoir unable to be completed with intelligent well systems.

Drilling long horizontal wells through the reservoir is challenging for several reasons. The length of the section increases the torque and drag, and with limited down-weight available it may be difficult to run the casing to the target depth. In addition, long horizontal sections are difficult to cement properly. A good cement job is needed to ensure zonal isolation which is required in order to have an effective intelligent well completion.

The drilling difficulties sometimes make it necessary to drill the reservoir in two sections, i.e. to use the contingency casing design. The contingency does not allow for an intelligent well system since the diameter is reduced in the last section of the reservoir. This means that the zones in the last reservoir section cannot be selectively produced which may reduce the hydrocarbon recovery of these zones.

Expandable technology may be a solution to the well construction problem in some cases. Expandable liners may give an additional casing point with a minimum reduction in hole size or no size reduction at all; a monodiameter solution. An expandable liner that is included in the initial casing design enables longer wells to be drilled, wells with larger hole sizes at the reservoir, or slimmer top hole sections. If the system is used as a contingency it enables one to isolate problem zones and still reach the target depth with the same size.

There are several advantages with expandable technology. Expandable technology provides the option of having one or more casing points with little or no reduction in well diameter. This means that deeper reservoirs, which could not have been reached with conventional technology, can be reached, or reservoirs can be reached with a larger diameter hole. As demonstrated in the theory section of this thesis, the diameter of the production tubing affects the flow rate significantly.

Expandable technology also provides the option of reducing the top hole sizes and thus reducing environmental and economical impacts. A slimmer hole results in environmental benefits such as reduced drilling fluids volume, cement volume, and cuttings for disposal. In addition, less material is needed for casings as their diameter can be made smaller.

Economic benefits include development of smaller fields and deeper reservoirs and reduction in volume of drilling fluids and cement. In addition, a reduction in casing sizes lowers the weight that the drilling vessel needs to support. A smaller drilling vessel can therefore be used, which may reduce the cost significantly. Since expandable technology may enable the use of smaller hole sections, the drilling speed may be increased. Drilling a smaller hole means that the necessary cuttings transport is reduced. The cuttings transport is often a limitation to the drilling speed and a reduction in cuttings may sometimes lead to a higher drilling speed. An increased drilling speed gives large economic savings, mainly due to reduction of rig time.

The properties of the pipe are affected by the expansion process. The pipe is expanded in a cold working process giving work hardening of the material, which increases the yield strength of the material. As the yield strength of the material increases the burst pressure may increase, depending on the wall thickness reduction and expansion ratio. However, the yield strength does not affect the collapse strength for pipes with high D/t ratio since these pipes fails elastically. An increase in yield strength may compensate for some of the collapse pressure reduction for pipes with low D/t ratio; however, the collapse pressure is usually reduced significantly in the expansion process because the D/t ratio increases. This reduction in collapse pressure is also seen from tests of collapse pressure. As demonstrated in the theory section (chapter 2.5.5) the API equations for collapse are quite consistent with the tests of collapse pressures of expanded pipes. The graph in Figure 2-25 shows that the collapse pressures given by the service provider and the calculated collapse pressures show the same trend and the difference between them decrease as the D/t ratio increases. This is consistent with other tests found in the literature (Butterfield et al., 2007). The load properties of the post-expanded pipe may limit the range of application, since casings may need to withstand a certain collapse pressure.

The solid expandable liners are not qualified as barriers or to be exposed to well fluids. Because of this, in addition to the reduced collapse pressure, the expandable liners are often used as drilling liners. This means that the expandable liner does not need to be strong enough to handle production loads, only drilling loads. Another liner or casing is used to case off the expanded liner before production or injection starts. As the casing designs performed in this thesis shows, the expandable liners should be able to handle the loads during drilling of the last reservoir section.

There are several possible solutions to the well design problem using expandable technology. Which solution that is best depends on the application and the particular well conditions. Solid expandable liners have been the focus of this thesis and the case study, but there are also other expandable products such as expandable screens that might be a solution.

In this thesis, the basis is that the casings above the reservoir are set according to the current well design. The expandable solutions may then be used in the reservoir sections. The alternative would be to use expandable tubulars above the reservoir to be able to drill into the reservoir with a larger diameter bit. However, well integrity issues may arise if doing this. A blowout scenario may occur in the first section of the reservoir and a relief well may have to be drilled. This relief well ties in to the last casing, in this case that would be 13 3/8” casing or an equivalent size. In these large hole sizes, the pump rate needs to be very large to be able to kill the well. The reason for this is that the frictional pressure drop upwards in the hole is less than in a smaller hole. The rig pumps are not powerful enough to handle such a scenario.

One alternative is to set an expandable liner in the first section of the reservoir and expand it into the previous liner, which has 9 5/8” outer diameter in the current well design, and keep the above casing strings unchanged relative to the current well design. The solid expandable liners that are available today are not qualified as barrier elements or to be exposed to well fluids. This means that if these expandable liners are to be set in the reservoir, they need to be cased off before production or injection begins. If the expandable liner can be expanded to approximately the same inner diameter as the base casing, i.e. a monobore solution, a 7” liner can be run through both reservoir sections with the liner hanger in the 9 5/8” base casing. In this way the expandable liner is cased off and is not exposed to well fluids, and it still enables drilling of two reservoir sections while reaching the target depth with larger hole size than the standard well design. If a monobore solution is not used, the base casing may have to be changed to still be able to run a 7” liner through the expandable liner afterwards. This means that a 10 ¾” base casing may have to be used instead of a 9 5/8” base casing to be able to run a 7” liner through the expanded liner. Different load scenarios have been considered for these alternatives and it showed that the expandable liners should be strong enough to handle drilling loads if lost circulation zones are not encountered. If lost circulation zones are encountered, however, there is a risk of collapsing the liner.

Another alternative for reaching the target depth with a larger diameter liner is to set the 7” liner according to the standard well design, and then run an expandable liner in the last section of the reservoir instead of the contingency liner. However, since the liners are not qualified as well barriers or to be exposed to well fluids, this is not a practical alternative. In addition, the inner diameter of this last liner is not large enough to accommodate the intelligent well system used on the particular field studied. The casings/liners need to be drifted to 6.1” to allow for the intelligent well system. An expandable liner that is to be expanded to 7”, is usually 5 ½” pre-expansion. This cannot be expanded to 6.1” inner diameter. As Table 3-1 shows, the post-expansion drift in this example case is 5.511”, which is too low for this specific application.

The alternatives including expandable liners may be a good solution for wells where the limiting factor is related to rock mechanics. In partially depleted reservoirs the mud window may be narrow. Some zones may have the initial high pore pressure, while some are depleted. The well pressure needs to be between the pore pressure and the fracturing pressure in the entire open hole section. If drilling through several of these zones, in which some have high pore pressure and some have low fracture pressure, there may have to be set a casing to case off one or more zones before drilling can be continued. An expandable liner can then be used to minimise the ID reduction. However, the pressure conditions in the well may also be a problem for the expandable liners because of the post-expansion pipe properties. As shown previously, the collapse strength of the expandable liner is reduced significantly when expanding the pipe.

Other reasons for using expandable liners may be cementing problems. It may be difficult to ensure a good cement job and zonal isolation for wells in which the reservoir section is long. It may then be an advantage to case and cement the reservoir in two sections because a shorter distance would have to be cemented each time. Elastomers could also be used together with expandable liners to provide zonal isolation.

The first solid expandable liner was installed in 1999, and since then they have been installed in many wells. However, there is little experience with these in the Norwegian sector of the North Sea. Baker Oil Tools' linEXX™ system is a contingency for two fields in the North Sea. The 9 5/8" liner is set with a recessed shoe and the liner is to be installed if differential pressures in the reservoir are greater than a certain value. To date, six installations of the recessed shoes have been done, but the liner itself has not been needed because of the observed differential pressures were lower than expected. The linEXX™ system has however been installed commercially elsewhere, see chapter 3.2.4.

There are other systems, like Enventure's SET® systems, that have been used more; however, this system does not give a monodiameter section and one may then have to make changes to the casing design above the reservoir to be able to reach the target depth with the same size.

To fully take advantage of the benefits that expandable technology offers, monobore wells should be realised. A multi-section monobore well would give large environmental and economic savings as the entire well could be slimmed down.

5 Conclusion

Expandable technology is a promising technology that can be used to solve some of the well construction challenges that are faced by operators today. This technology can be used as an enabling technology, which means that it will enable operators to drill wells that could not have been economically drilled with conventional technology. This entails, for instance, the drilling of deeper wells while still reaching the target with an economically viable well diameter. The tubing size affects the production rate significantly and small tubing may be a production limitation for the well. Expandable technology can also be used to optimise the well design, by for instance reducing the casing sizes in the top hole.

There are several applications for expandable technology, including both cased-hole applications and open-hole applications. In cased-hole applications, expandable technology may be used to blank off sections of perforations, repair damaged or corroded casing, or to reinforce and reline entire wellbores. In open-hole, an expandable liner can be used to seal off problem zones while still maintaining the inner diameter of the previous casing. Patches may also be used in open-hole to seal a zone.

Material selection is important for expandable products, and there are three states which have to be considered for the pipe in question; pre-expansion, during expansion, and post expansion. To be able to expand the pipe, the material's ability to yield and flow without failing is important. When the pipe is expanded, the yield stress is exceeded to plastically deform the pipe, but if the ultimate tensile strength is exceeded the pipe material will fail by tearing.

The yield strength of the material is increased in the expansion process because the material is work-hardened. This may cause the burst resistance of the pipe to increase, since it is dependent on the yield strength. The collapse resistance is reduced significantly, however. Thin-walled pipes fail elastically in collapse and the collapse resistance is not dependent on the yield strength. The D/t ratio of the pipe increases and this causes the collapse pressure to decrease, a result which tests done by others have confirmed.

Using API equations for collapse of pipes that fail elastically, which is typically the case for large pipes with a high D/t ratio, the theoretical reduction in collapse resistance has been calculated as a function of expansion ratio. As a worst case with no length reduction of the pipe, the collapse resistance is reduced by 44 % if the outer diameter is expanded by 10 %, and 67 % if the outer diameter is expanded by 20 %.

Comparing the design collapse resistances as given by a service provider and the collapse resistances calculated by the API equations, show that the difference is largest for low D/t ratios. The calculated collapse resistance is larger than what is actually given in the product specifications. As the D/t ratio increases the difference between the calculated collapse resistance and the given collapse pressure is reduced. This trend is also observed in tests found in the literature.

A reason for the difference in theoretical and observed collapse resistances may be that the wall thickness varies across the pipe cross section. This will magnify during the expansion process since areas with low wall thickness will be expanded more than areas with larger wall thickness. Stringent pipe inspection practices should be followed for pipes that are to be expanded to ensure optimum post-expansion properties.

Different load scenarios have been considered for two types of expandable liners and the result was that the expandable liners should be strong enough to handle the drilling loads. However, the expandable liners were not strong enough in collapse to handle lost circulation with mud drop in this case, but this should not be a problem if lost circulation zones are not likely to be encountered.

The systems considered were the linEXX™ system provided by Baker Oil Tools, and the SET® system provided by Enventure. The linEXX™ system gives a monodiameter solution, but there is less experience with this system than the SET® systems. Less experience usually means a higher degree of uncertainty. The advantage with a monodiameter solution is that the change in casing scheme is minimal.

The SET® systems give a decrease in the inner diameter. Since the intelligent well systems used on the Snorre field require an inner well diameter of 6.1”, the 9 5/8” production liner may have to be replaced with a liner that gives a larger inner diameter, for instance a 10 ¾” liner. The change in casing scheme is thus larger than for the system giving a monodiameter section; however, there should be less risk associated with running this system since there is more experience with it.

Assuming that the entire reservoir needs to be cased off, both systems considered might be a solution for the Snorre field. Both of these systems have advantages and disadvantages associated with them, and these would have to be considered before deciding which system to use in a specific well. If the operator is willing to accept some uncertainties in the operation, the monodiameter system would be favourable since the current casing design can be used above the reservoir.

As the technology improves, expandables may be used in the entire casing design of a well to realise the true potential of this technology. This will give large benefits as compared to the conventional well design since the hole sizes in the top hole may be reduced while still reaching the reservoir with an economically viable hole size.

The expandable products may offer substantial benefits as compared to conventional well design, and as the technology improves it may enable the construction of a monodiameter well. This would be very advantageous and create large economical savings as well as reducing the environmental impact.

6 Abbreviations

ABL®	Alternative borehole liner (Weatherford)
ACP	Annulus casing packer
API	American Petroleum Institute
Bcc	Body-centered cubic
Bpm	Barrels per minute
ECD	Equivalent circulating density
ECP	External casing packer
ESS®	Expandable sand screen (Weatherford)
EZI	Expandable zonal isolation (Weatherford)
FAWAG	Foam assisted water alternating gas
Fcc	Face-centered cubic
HETS™	Hydraulically expandable tubular system (Read)
ICV	Interval control valve
ID	Inner diameter
IOR	Increased oil recovery
IV-ICV	Infinitely variable interval control valve
MD	Measured depth
MSL	Mean sea level
OD	Outer diameter
OHC	Open hole clad
OHL	Open hole liner
PDO	Plan for development and operations
SCRAMS	Surface controlled reservoir analysis and management system
SET®	Solid expandable tubular (Enventure)
SPS	Subsea production system
TD	Target depth / total depth
TLP	Tension leg platform
TVD	True vertical depth
WAG	Water alternating gas
ZIB™	Zonal isolation barrier (Read)

7 Nomenclature

The list contains symbols, explanation and units in the SI-system.

F	Force [N]
A	Area [m^2]
σ	Normal stress [N/m^2 = Pa]
τ	Shear stress [Pa]
ε_t	True strain
ε_e	Engineering strain
σ_Y	Yield stress [Pa]
σ_u	Ultimate tensile strength [Pa]
p_{iR}	Internal pressure at ductile rupture of an end-capped pipe (API) [Pa]
a_N	Imperfection depth associated with specified inspection threshold (API) [m]
D	Outside diameter [m]
f_{umn}	Specified minimum tensile strength (API) [Pa]
k_a	Burst strength factor (API)
k_{dr}	Correction factor based on pipe deformation and material strain hardening (API)
k_{wall}	Factor to account for the specified manufacturing tolerance of the pipe wall (API)
n	Dimensionless hardening index used to obtain a curve fit of the true stress-strain curve derived from the uniaxial tensile test (API)
t	Specified wall thickness (API) [m]
ν	Poisson's ratio
σ_V	Vertical stress (overburden) [Pa]
σ_H	Maximum horizontal stress [Pa]
σ_h	Minimum horizontal stress [Pa]
ρ	Density [kg/m^3]
g	Acceleration of gravity [m/s^2]
p_o	Pore pressure [Pa]
σ'	Effective stress [Pa]
L	Length [m]
E	Modulus of elasticity, Young's modulus [Pa]
ν	Poisson's ratio
HR	Rockwell hardness
P_o	Pore pressure [Pa]
T_0	Tensile strength of rock [Pa]
μ	Fluid viscosity [Pa·s = 1000 cP]
Q	Flow rate [m^3/s]
ΔP	Differential pressure [Pa]

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Appendix A Casing Design - linEXX™

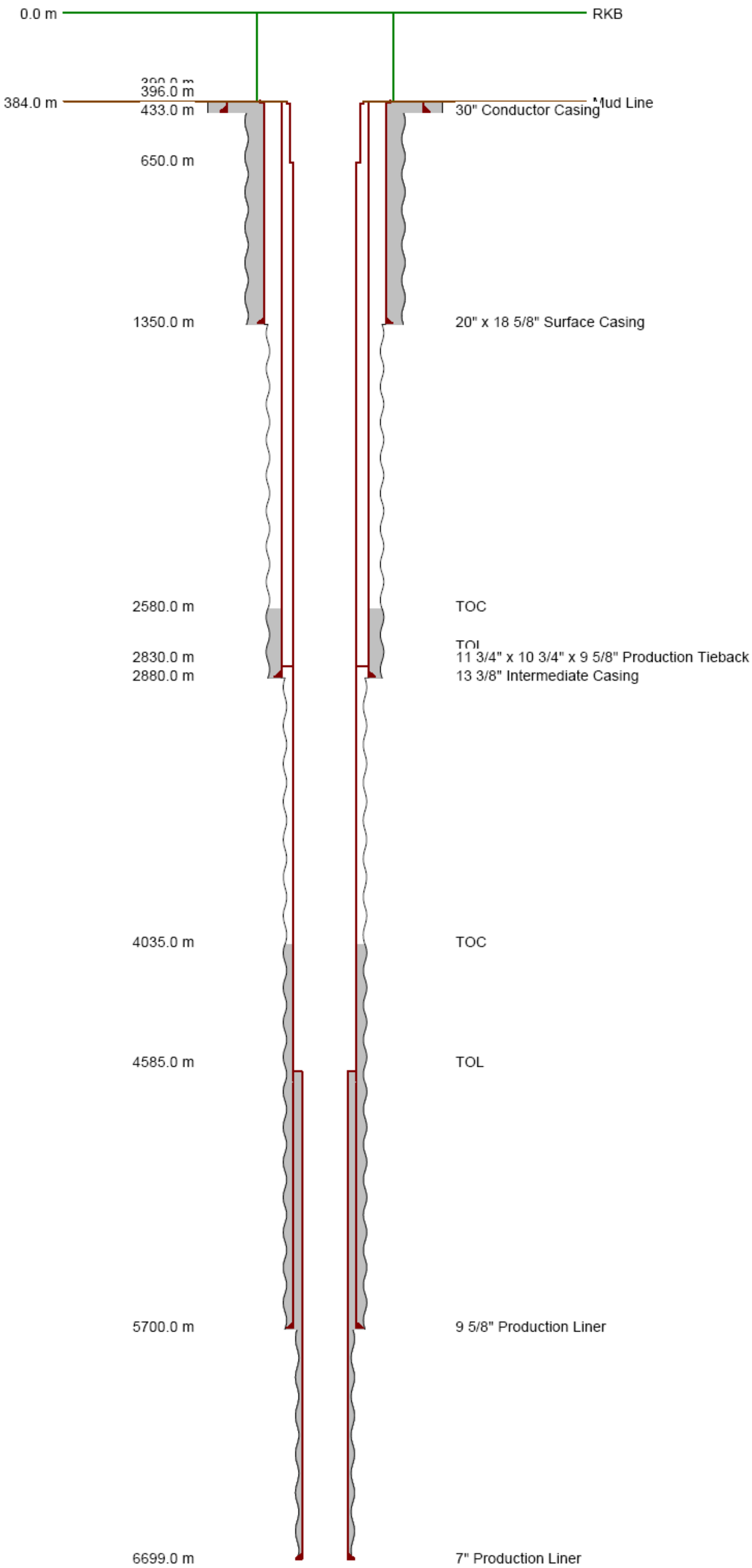


Figure A-1 Well schematic

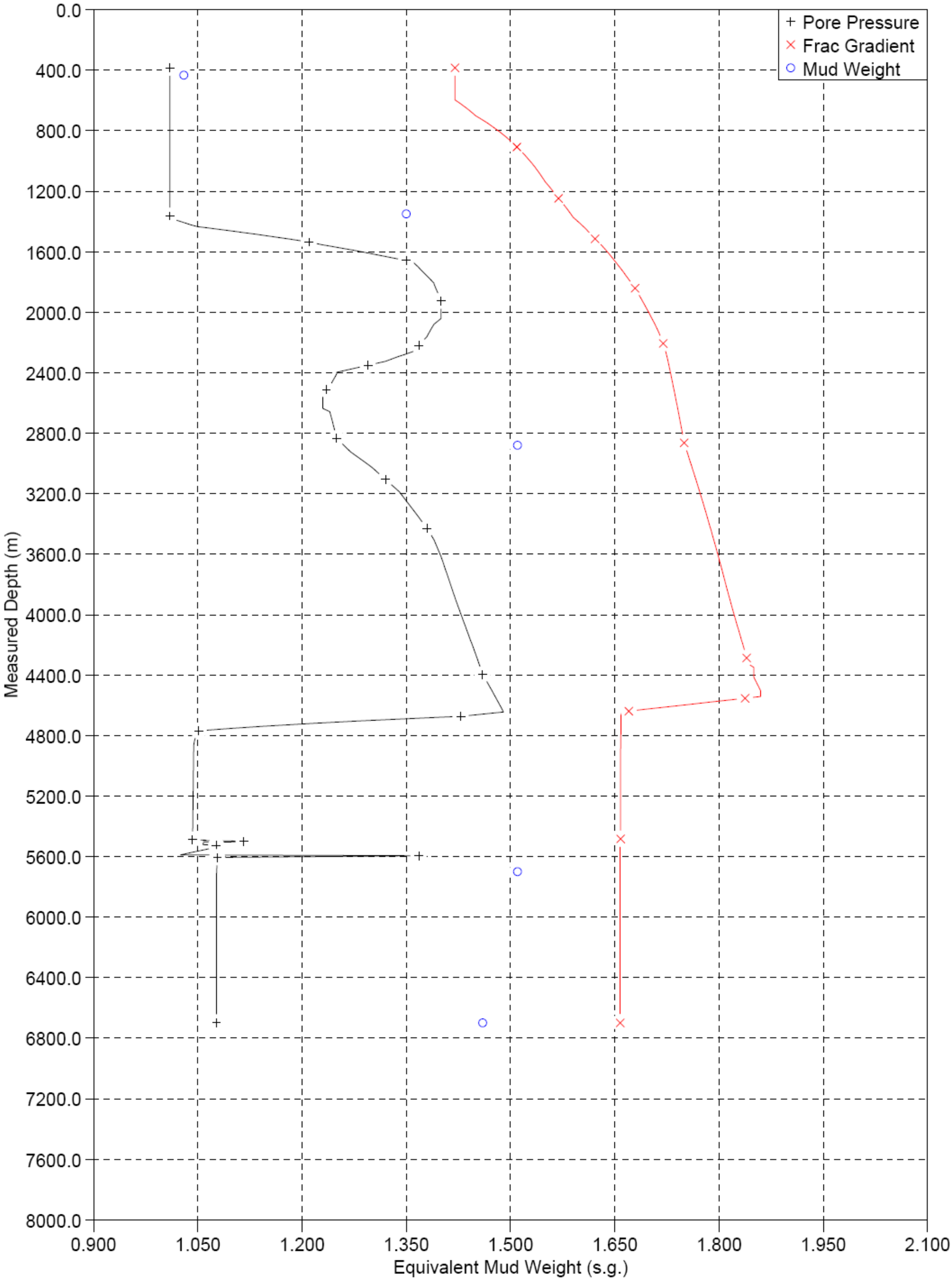


Figure A-2 Pore pressure gradient, fracture gradient and mud weights at the setting depths

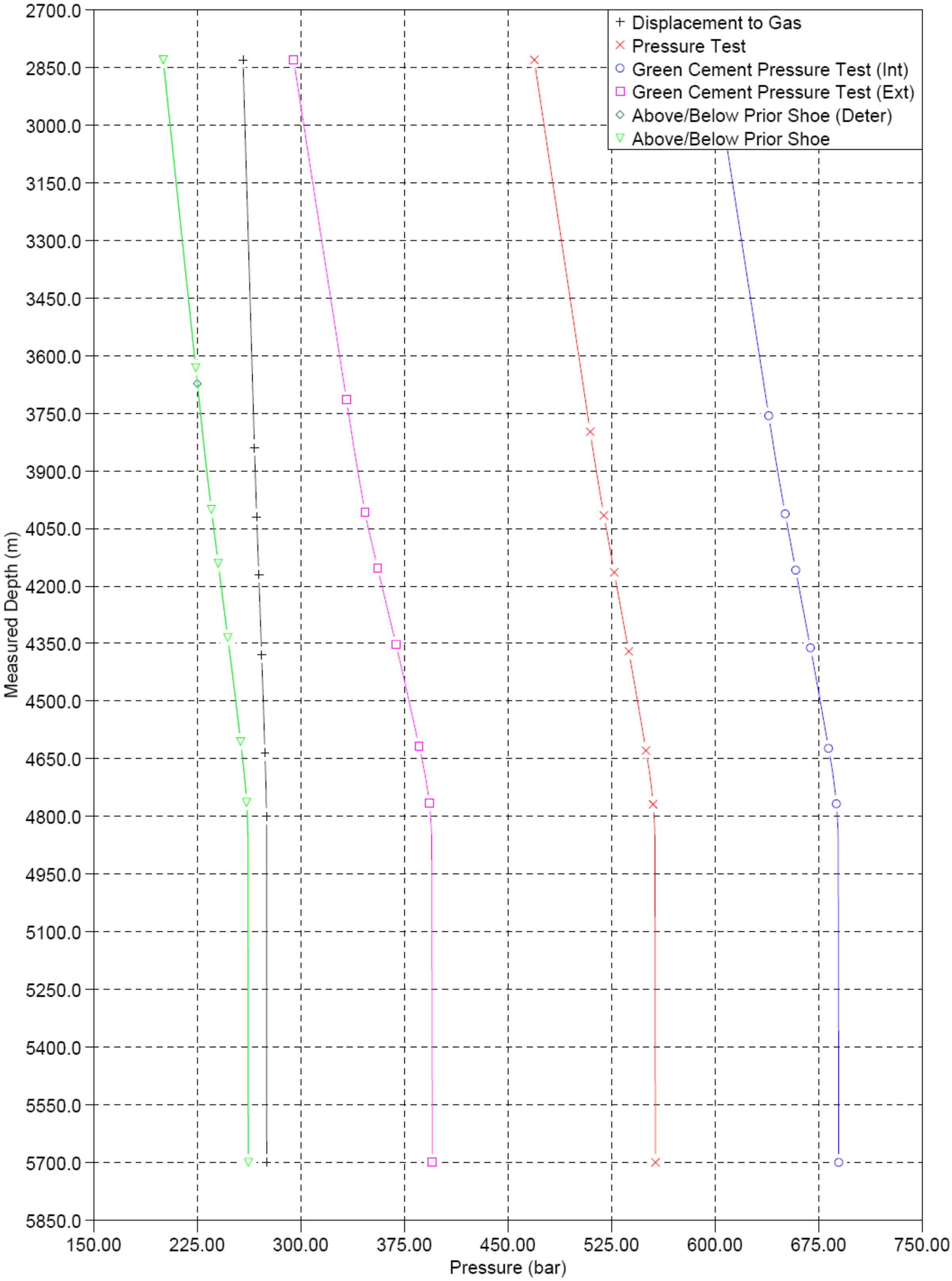


Figure A-3 Burst pressure profiles – 9 5/8" section

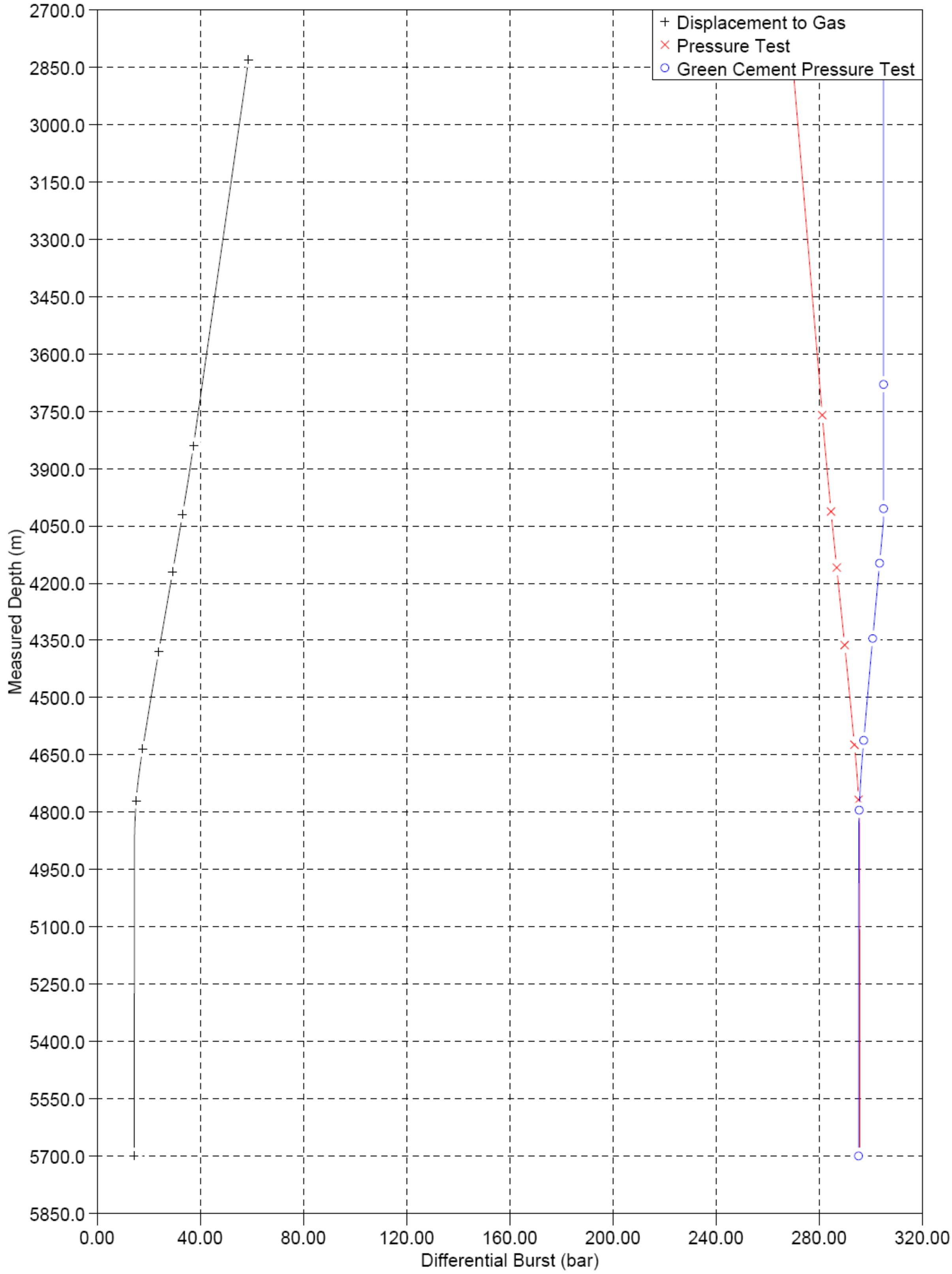


Figure A-4 Burst differential pressures – 9 5/8" section

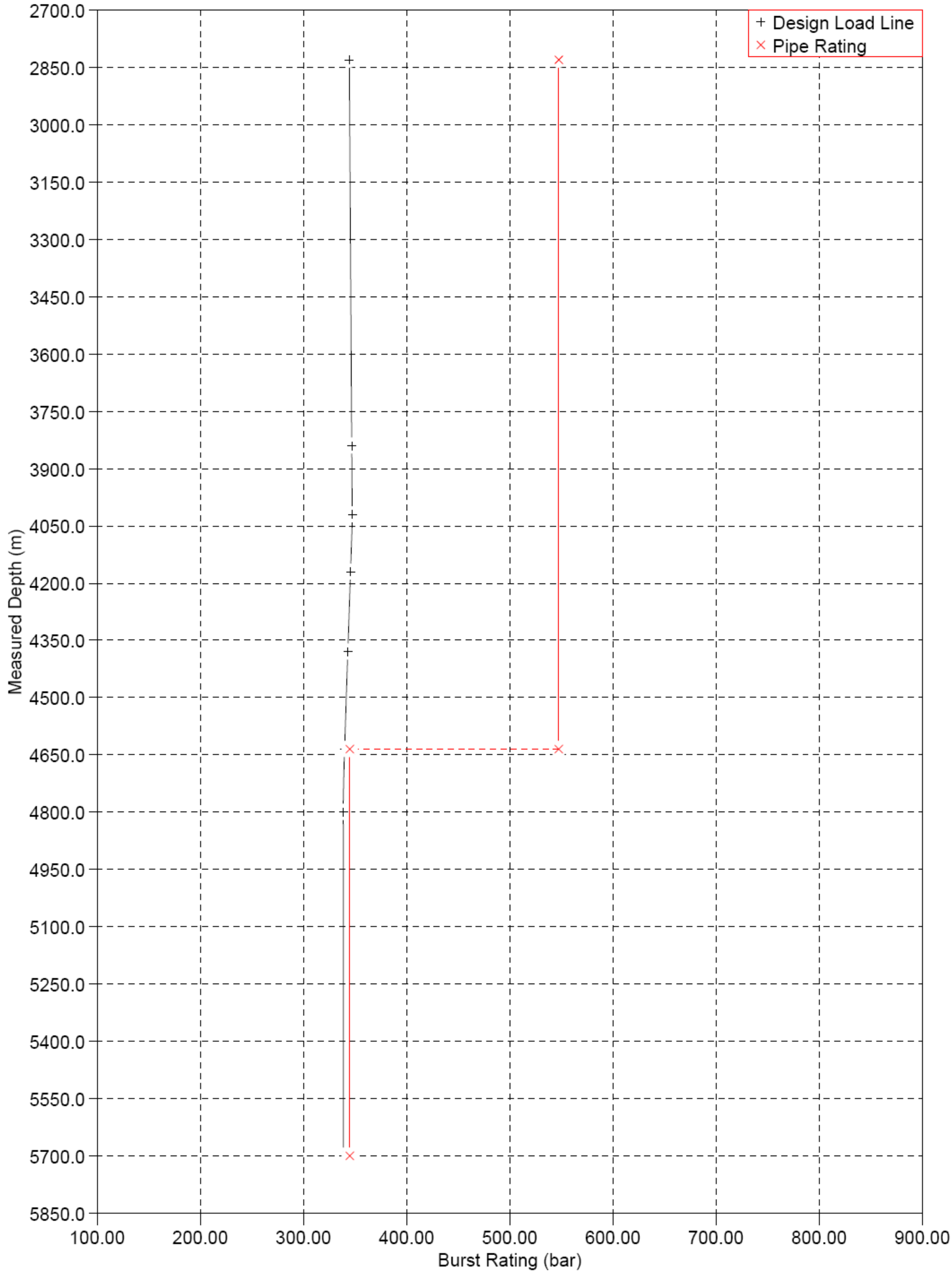


Figure A-5 Burst design - 9 5/8" section

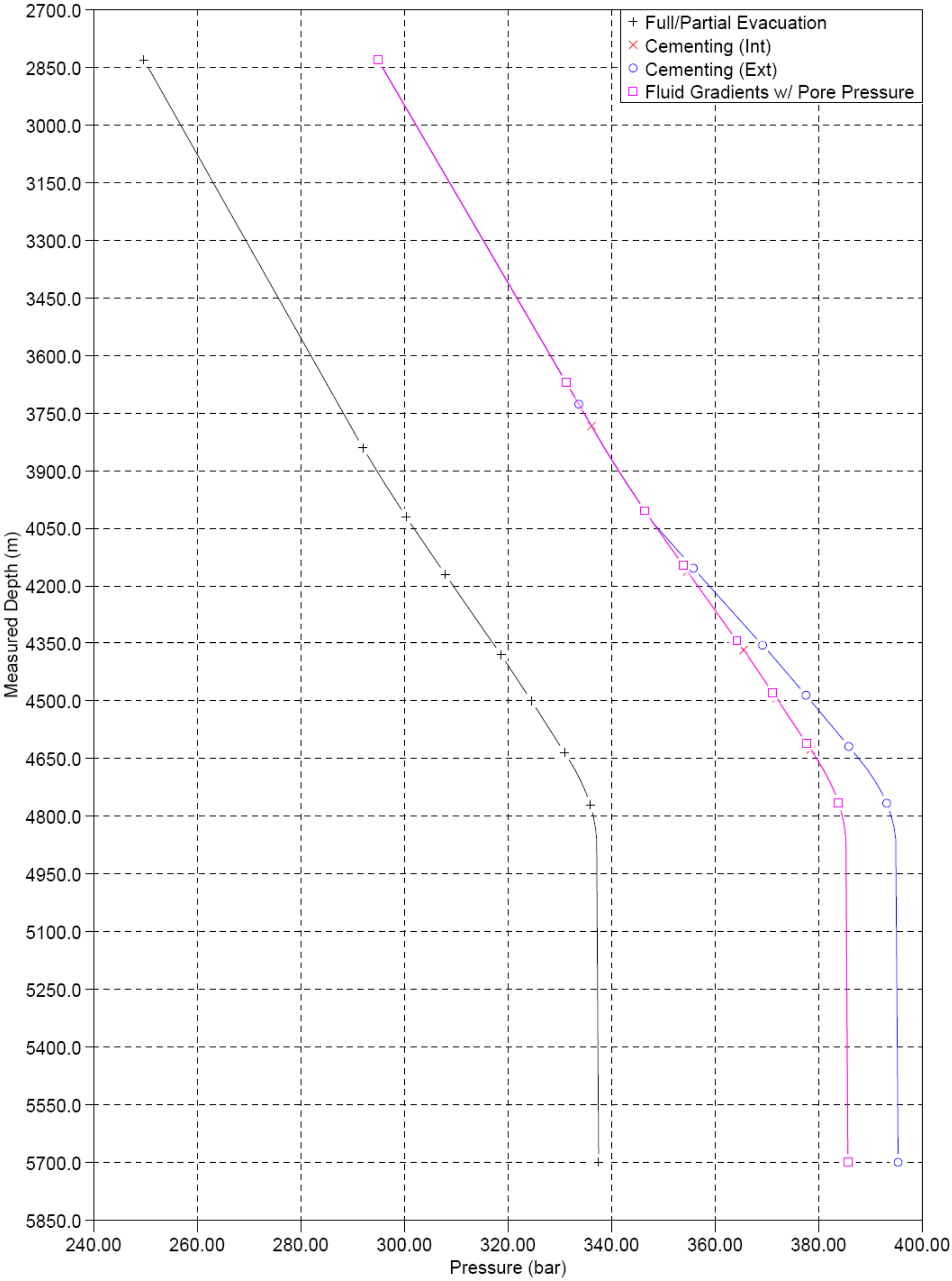


Figure A-6 Collapse pressure profiles – 9 5/8” section

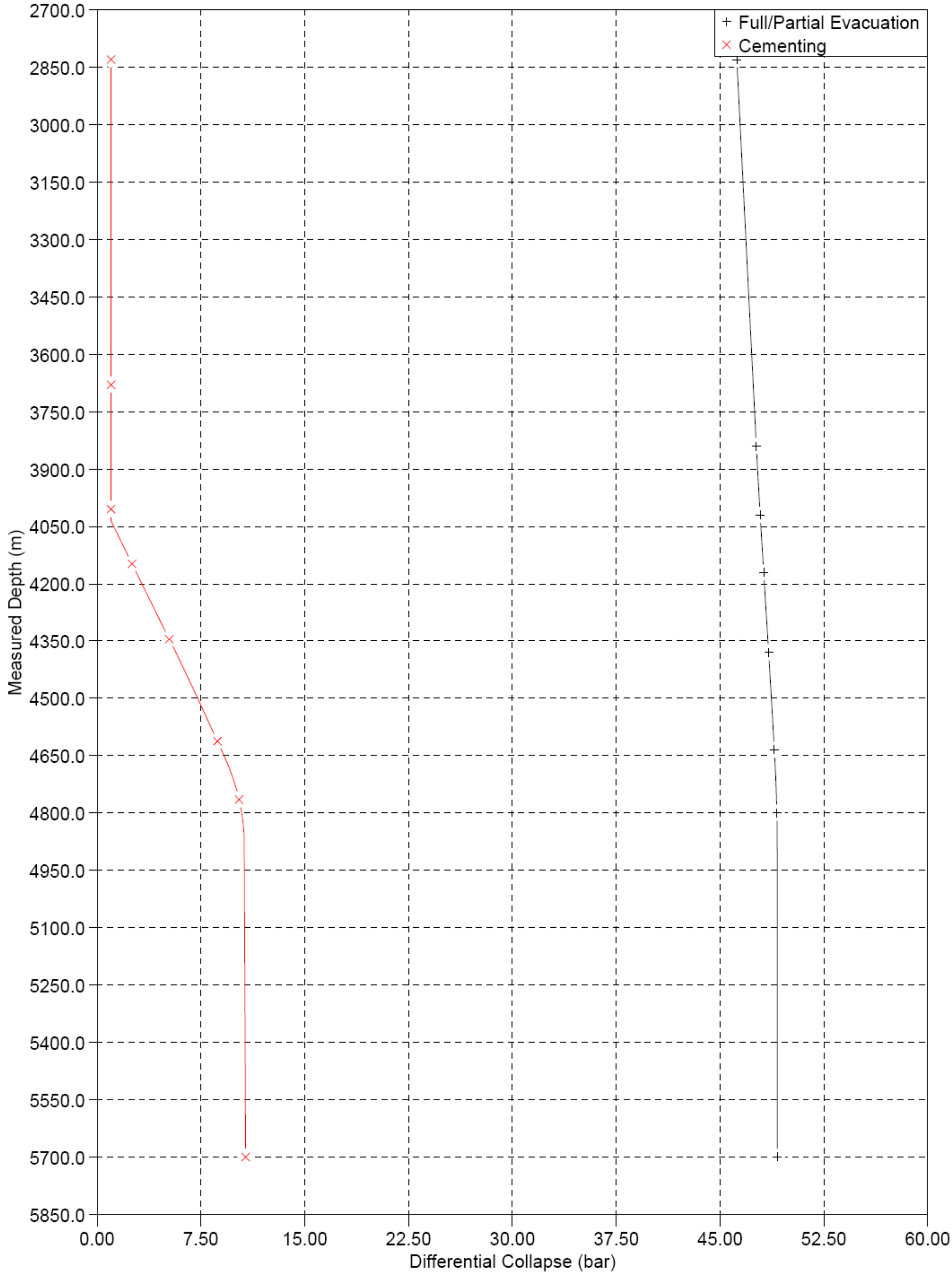


Figure A-7 Collapse differential pressures – 9 5/8" section

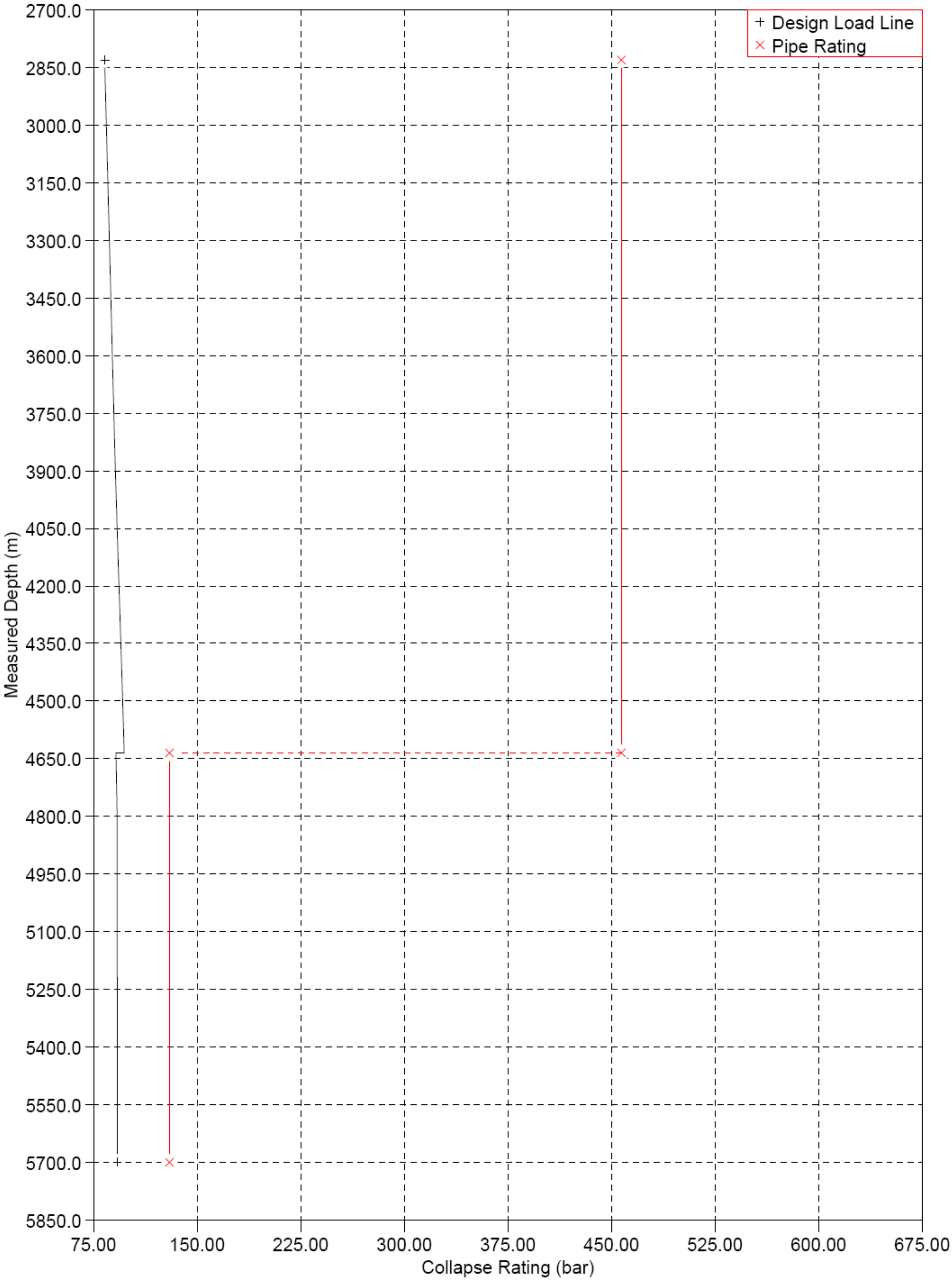


Figure A-8 Collapse design - 9 5/8" section

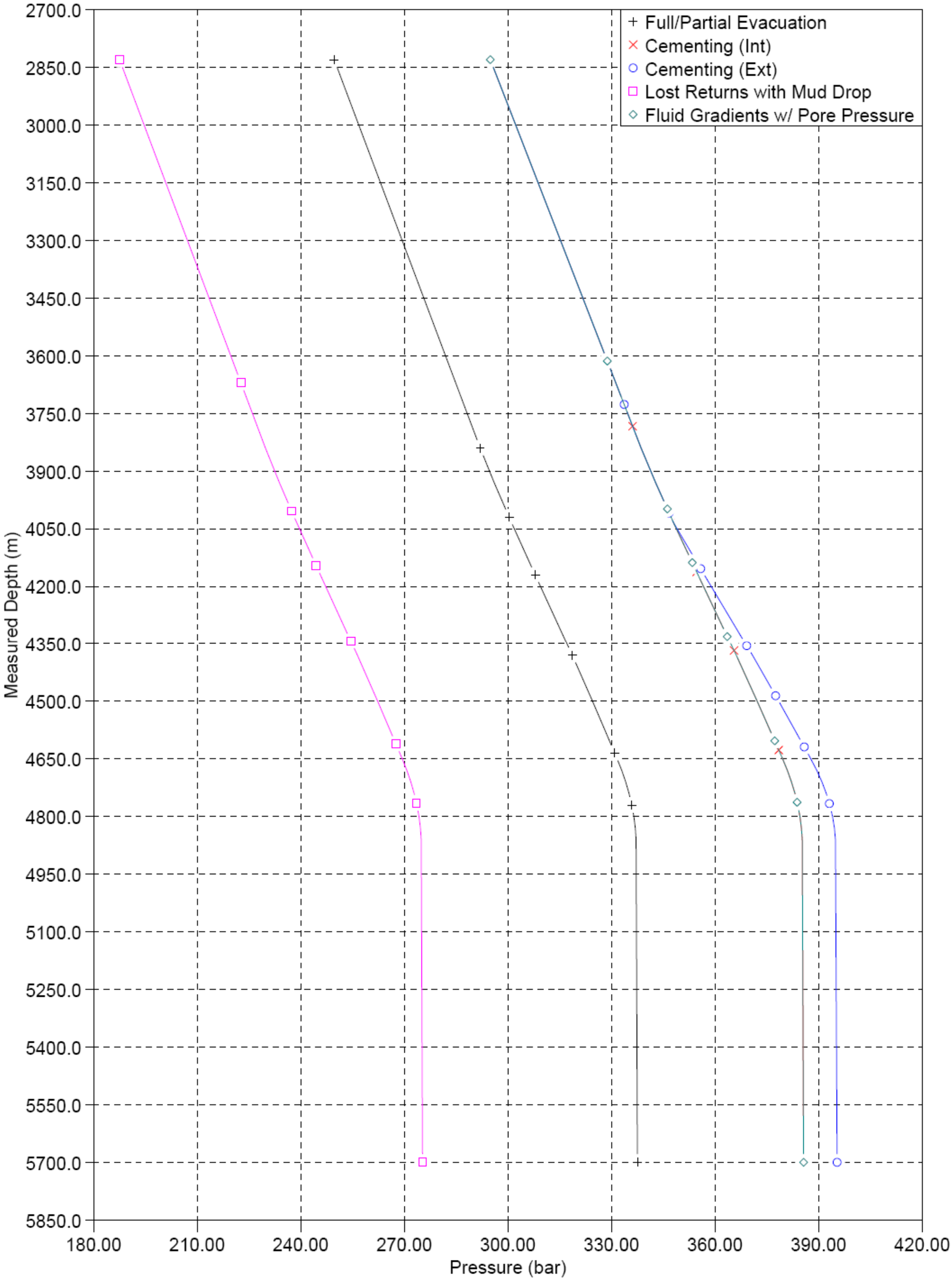


Figure A-9 Collapse pressure profiles including lost returns with mud drop - 9 5/8" section

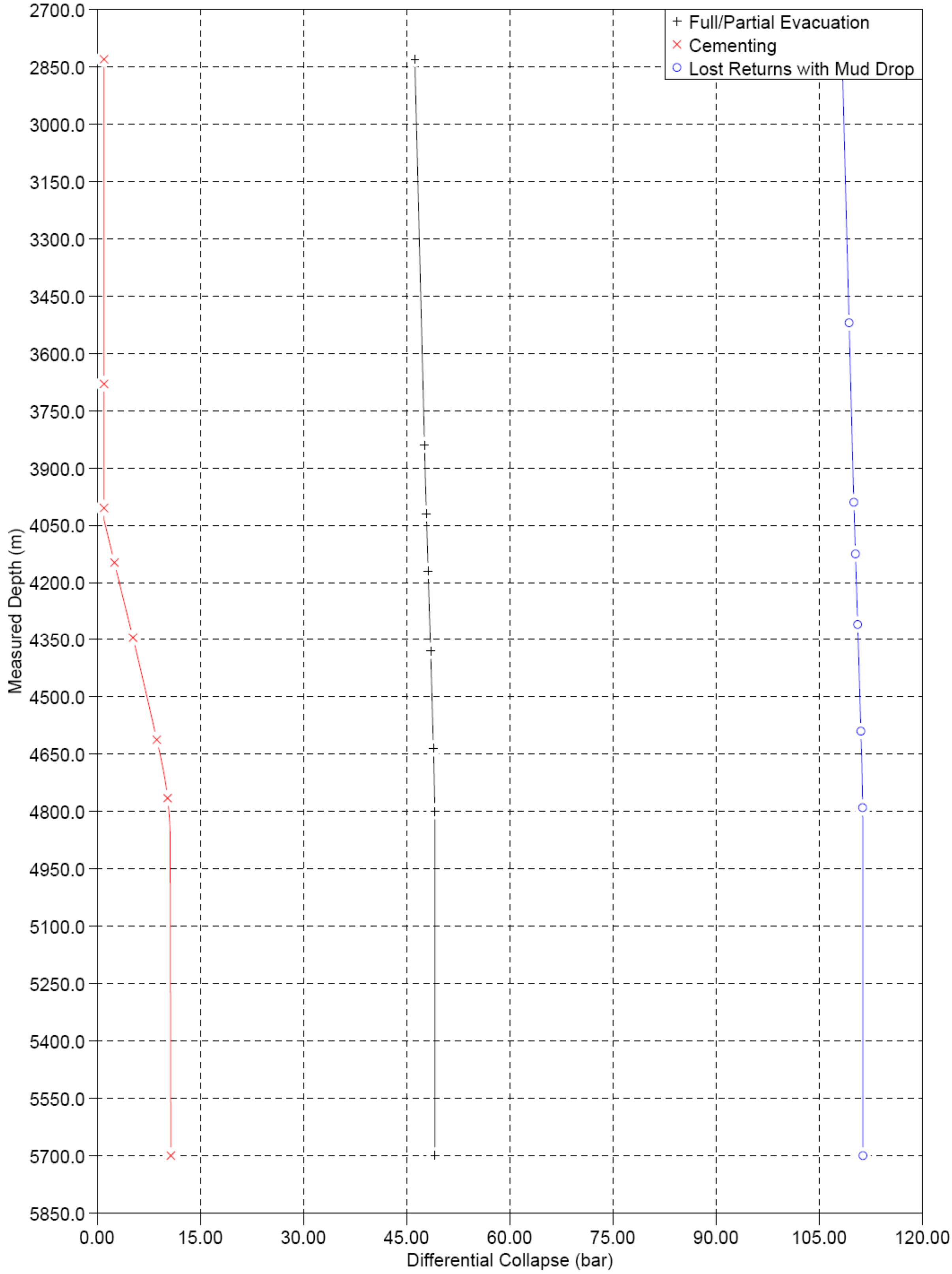


Figure A-10 Collapse differential pressure including lost returns with mud drop - 9 5/8" section

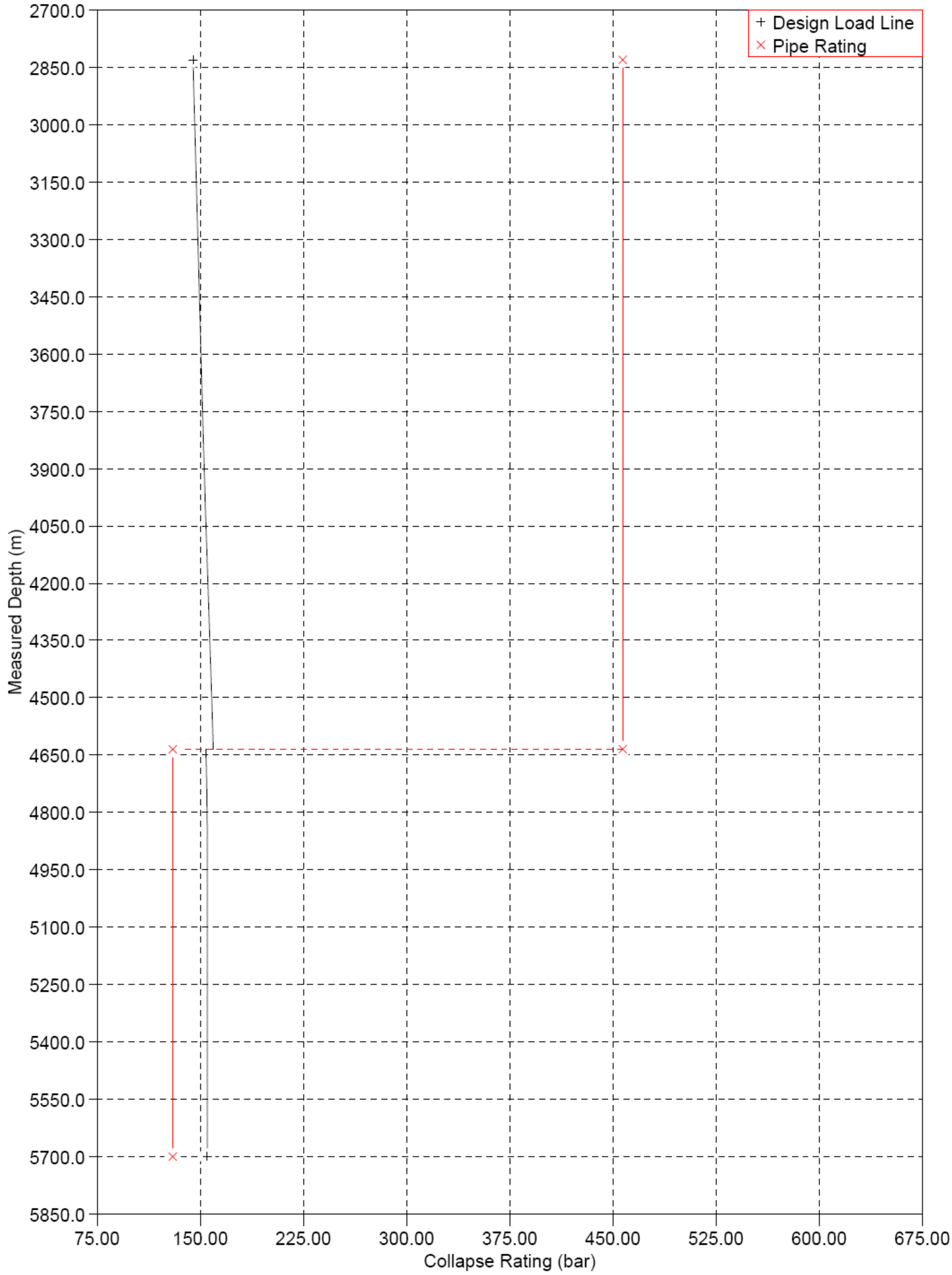


Figure A-11 Collapse design including lost returns with mud drop - 9 5/8" section

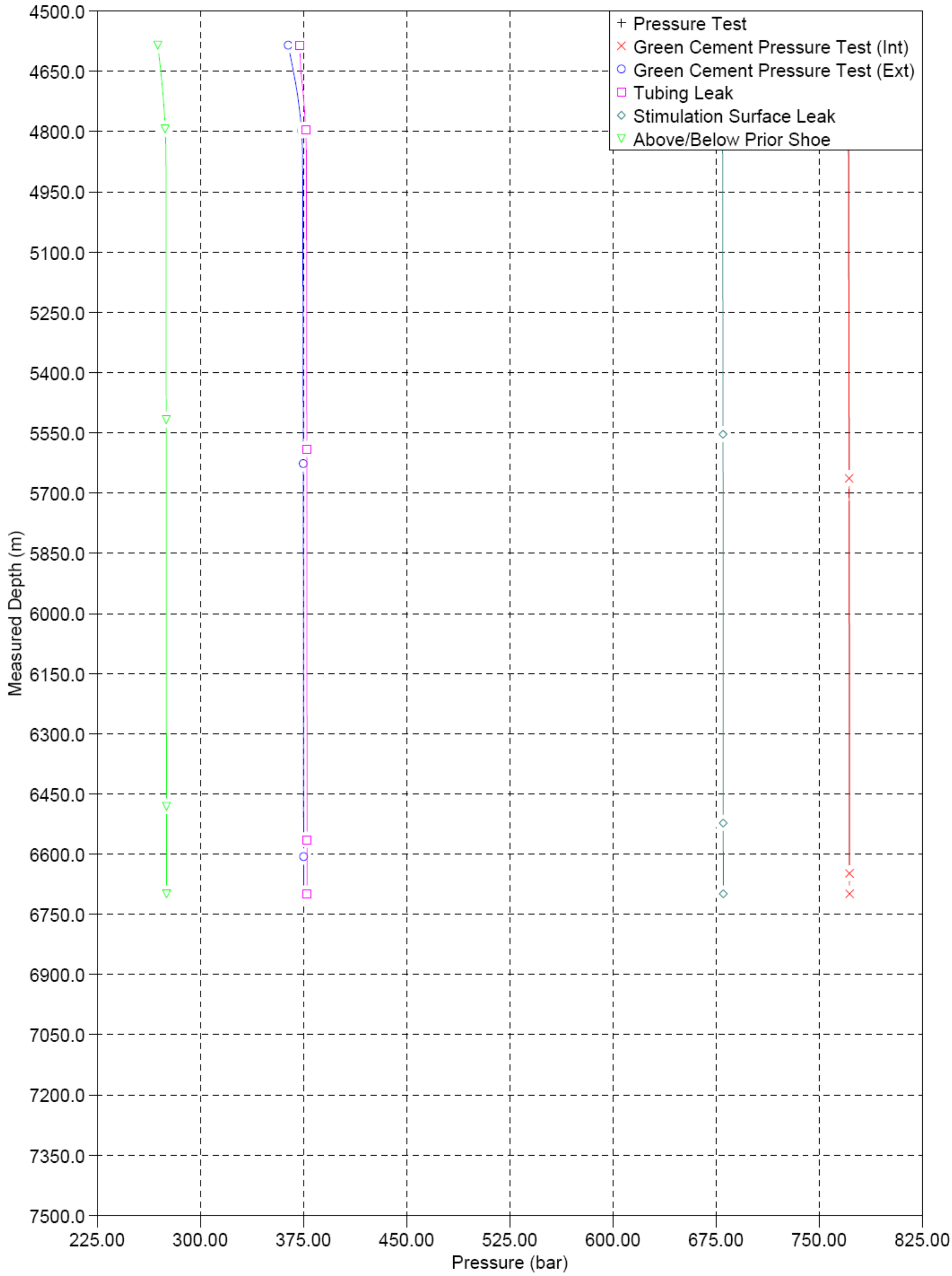


Figure A-12 Burst pressure profiles - 7" liner

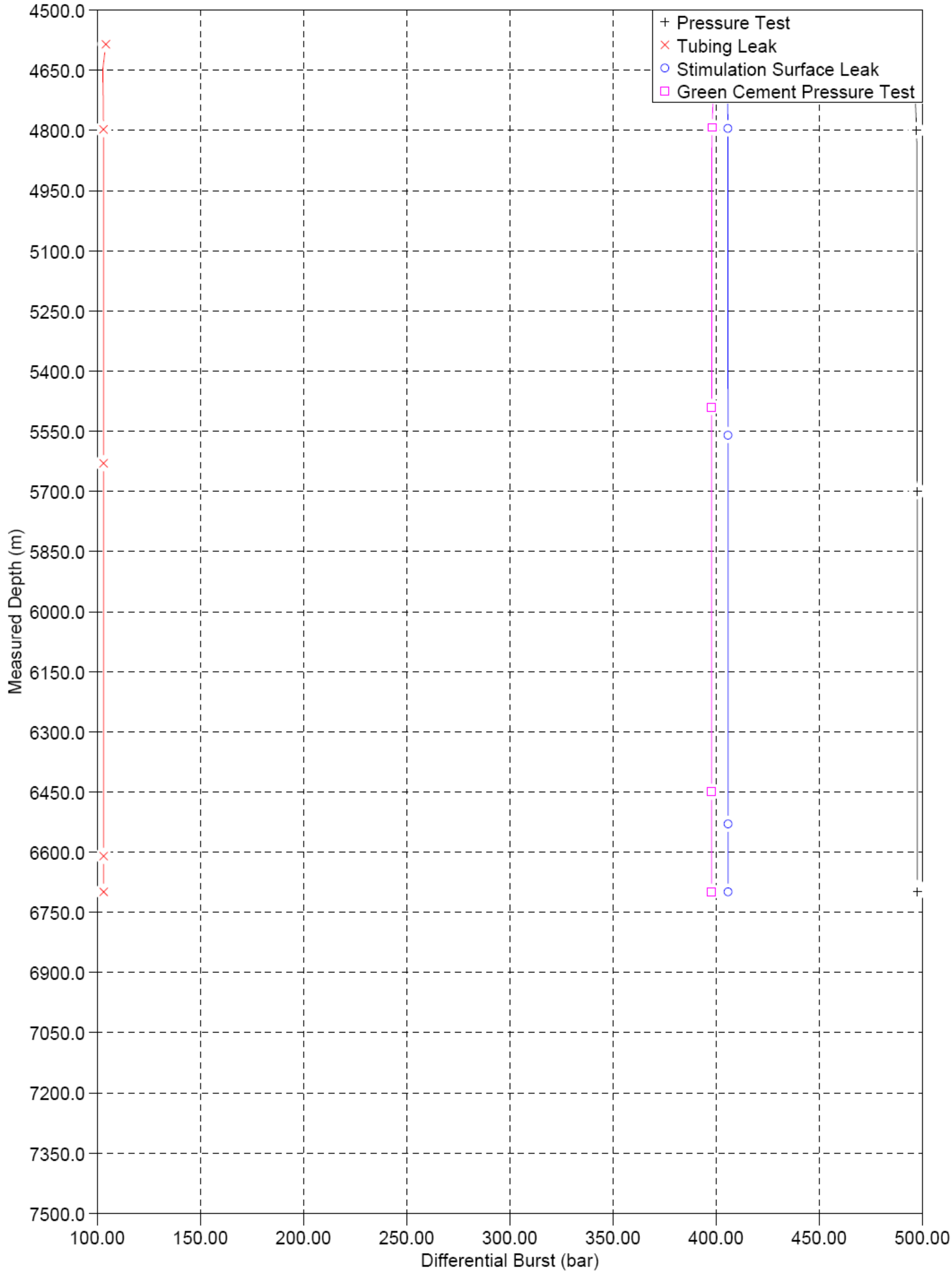


Figure A-13 Burst differential pressures - 7" liner

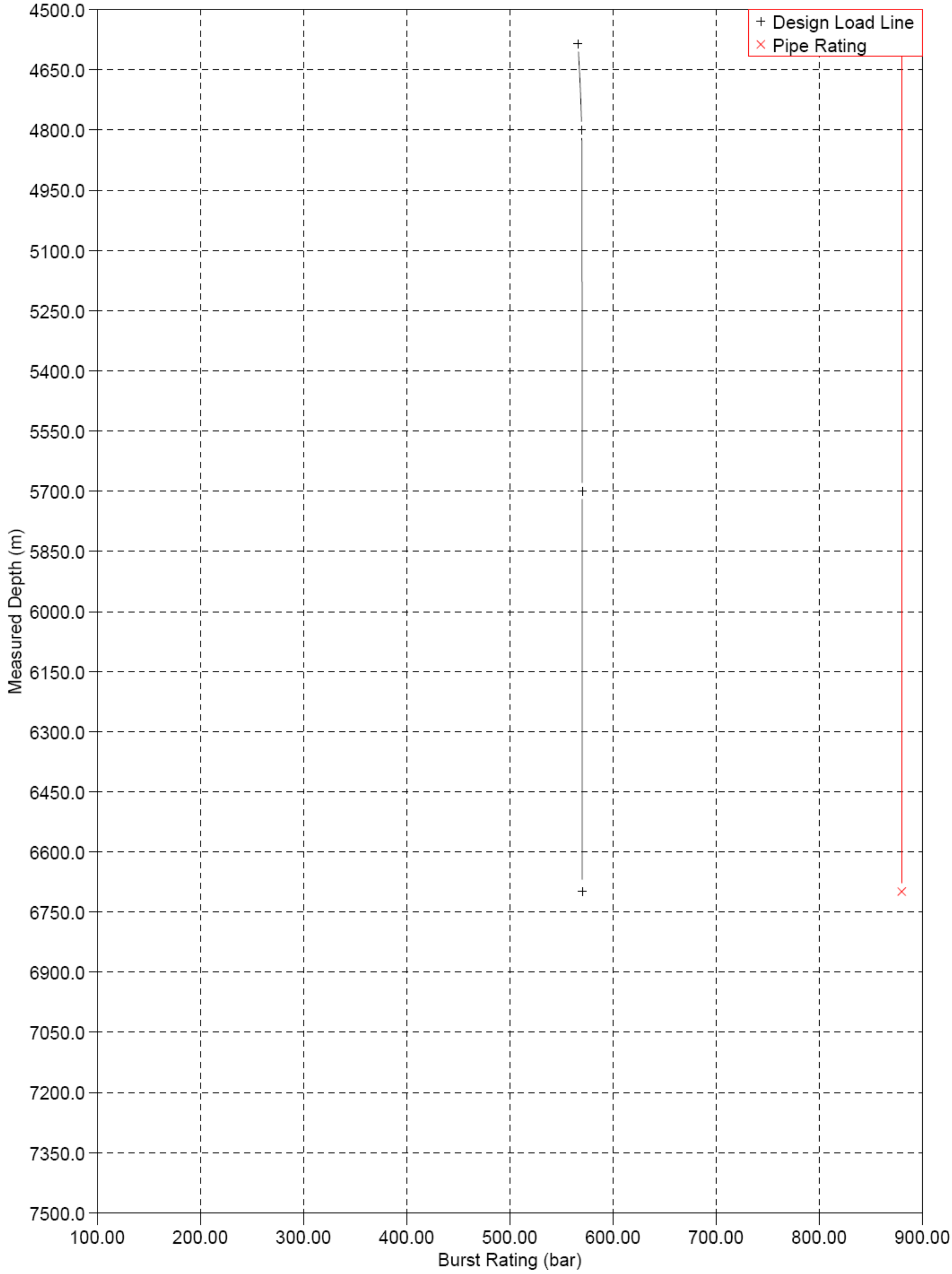


Figure A-14 Burst design - 7" liner

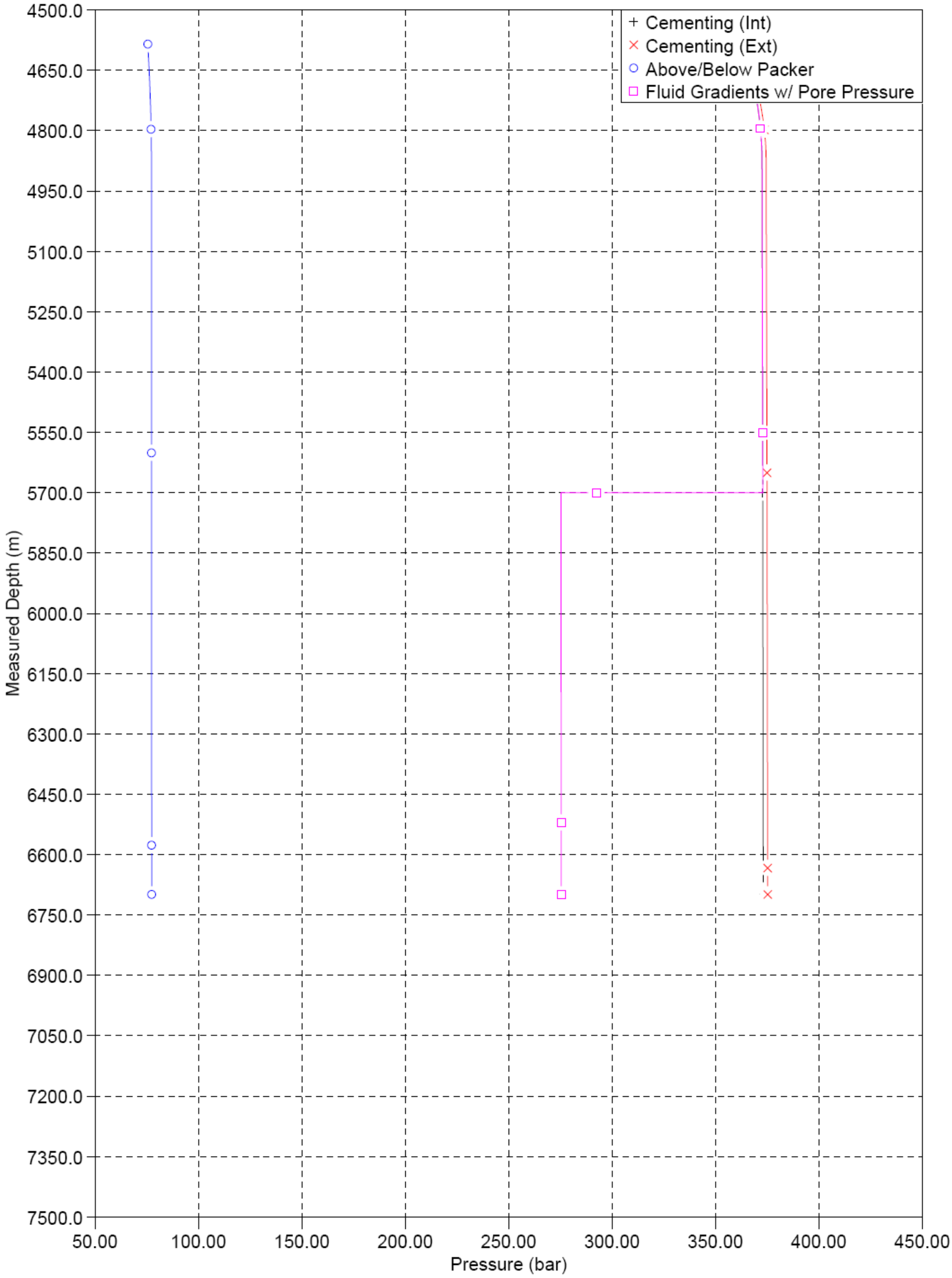


Figure A-15 Collapse pressure profiles - 7" liner

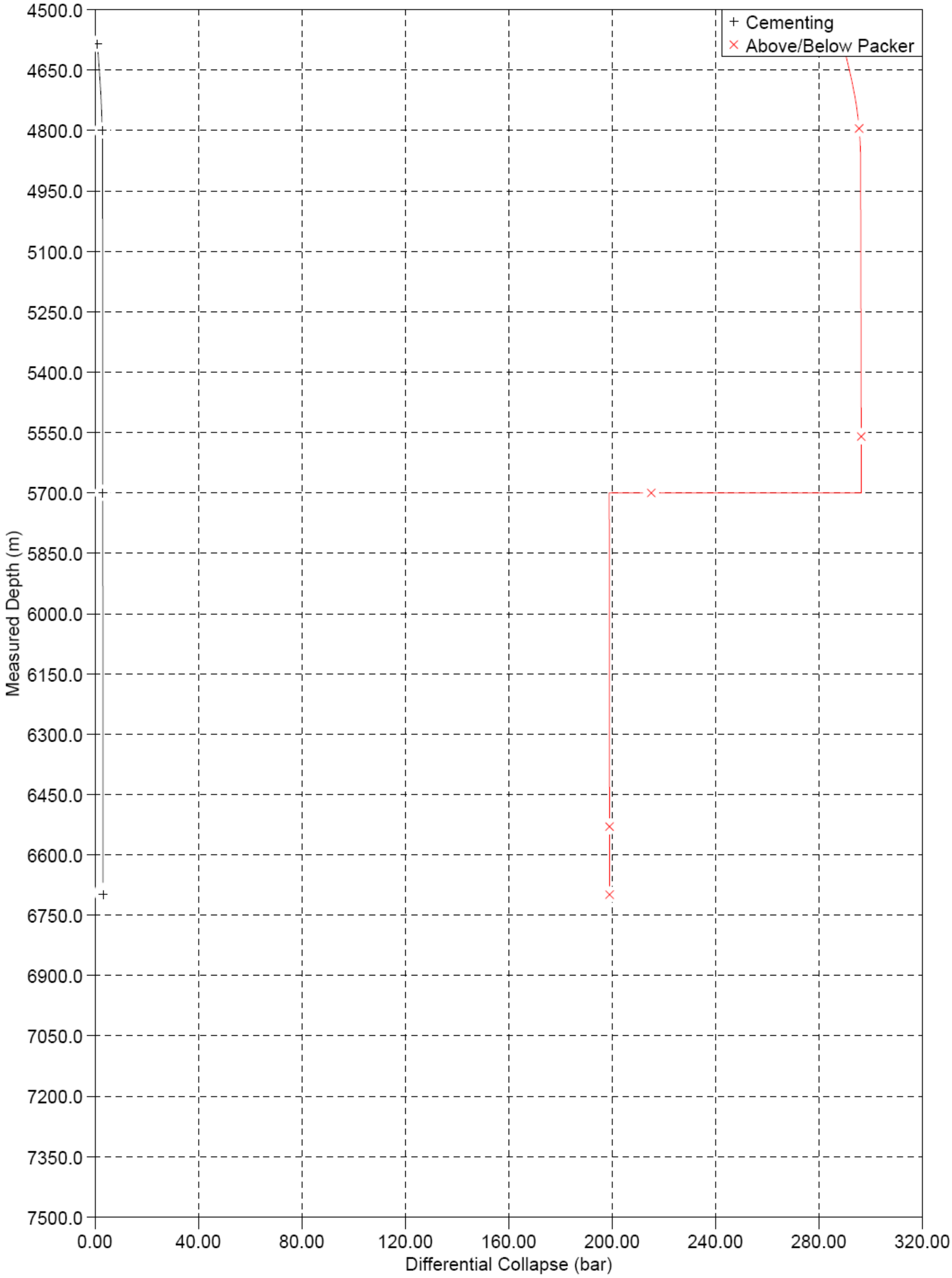


Figure A-16 Collapse differential pressures - 7" liner

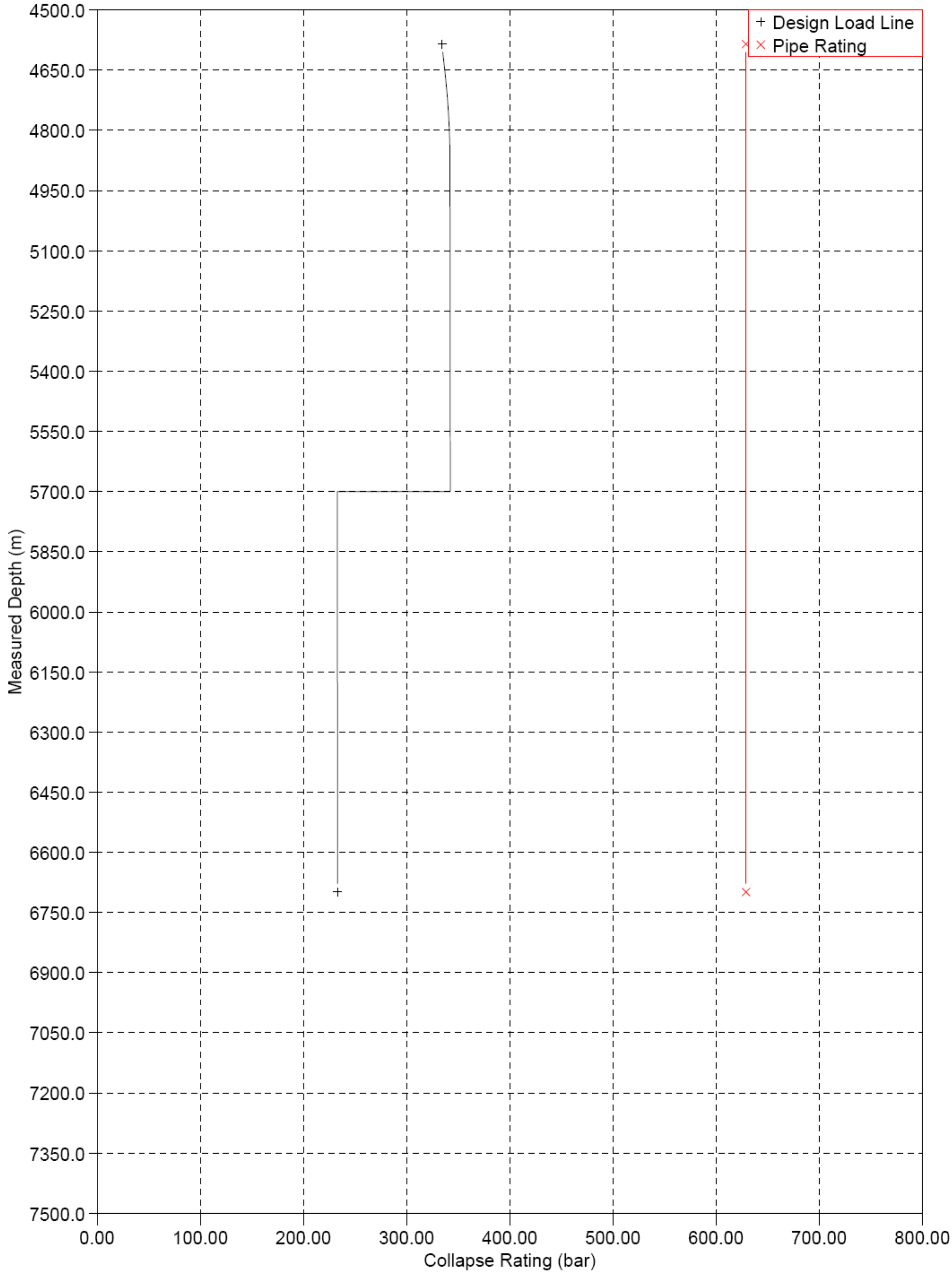


Figure A-17 Collapse design - 7" liner

Appendix B Casing Design - Enventure SET®

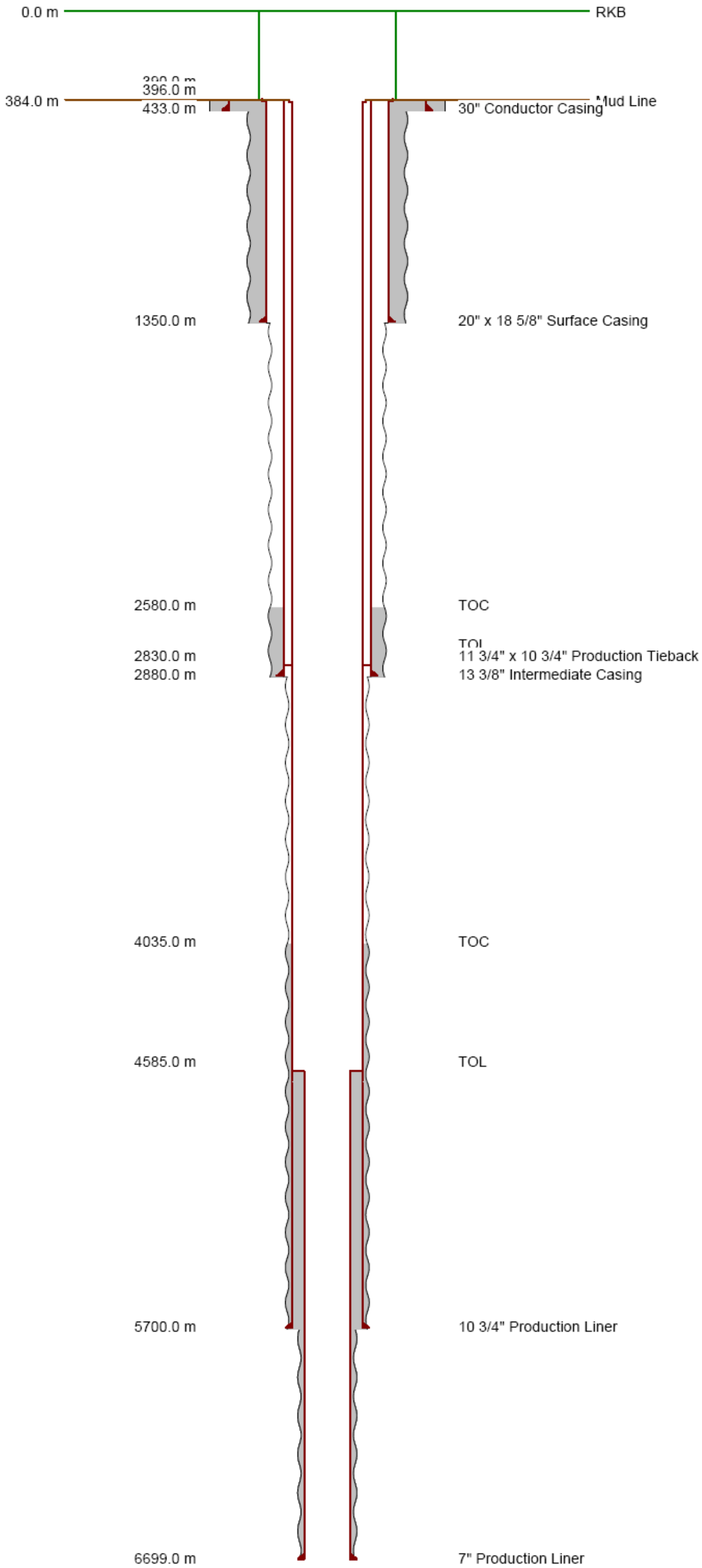


Figure B-1 Well schematic

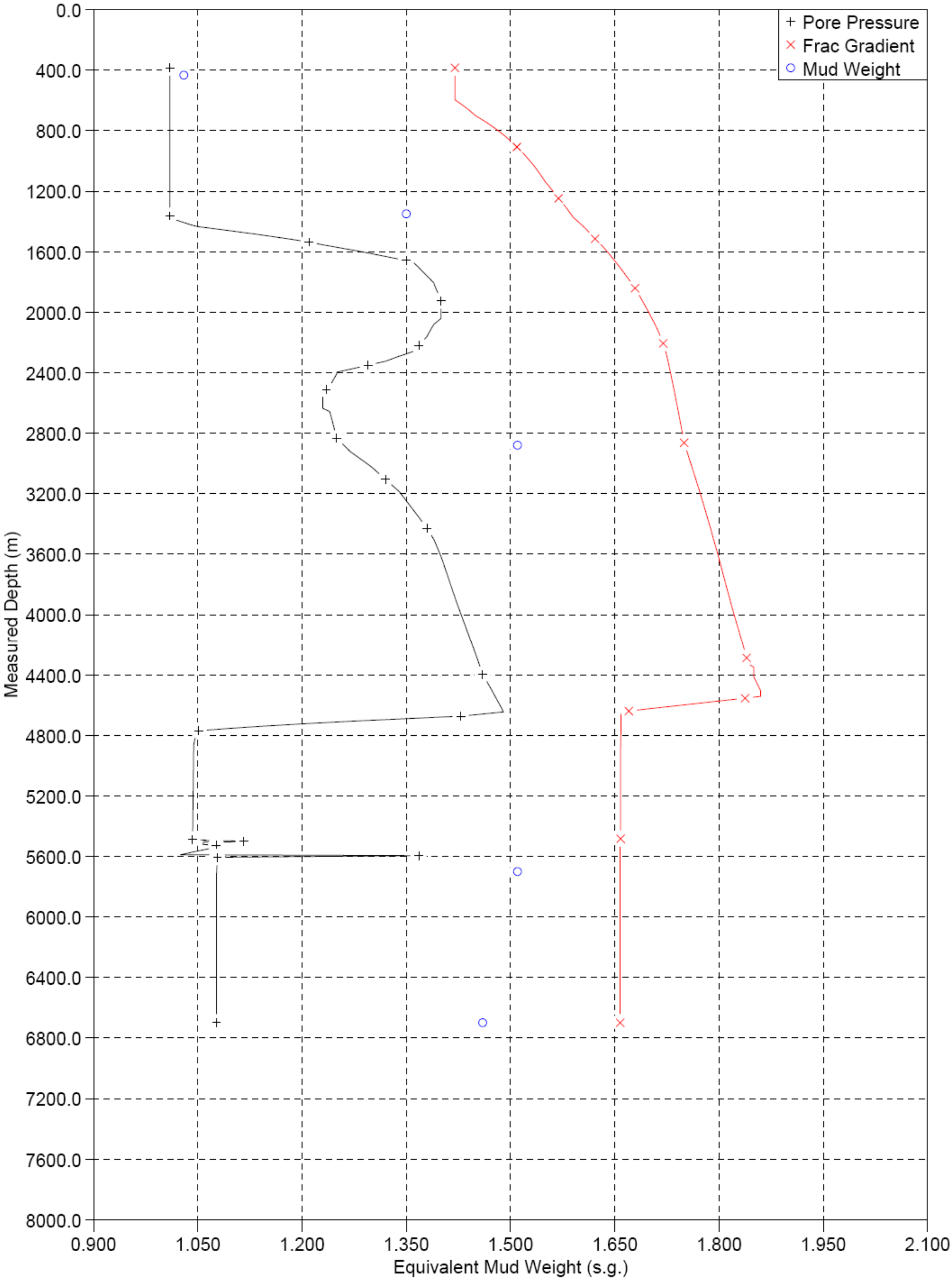


Figure B-2 Pore pressure gradient, fracture gradient and mud weights at the setting depths

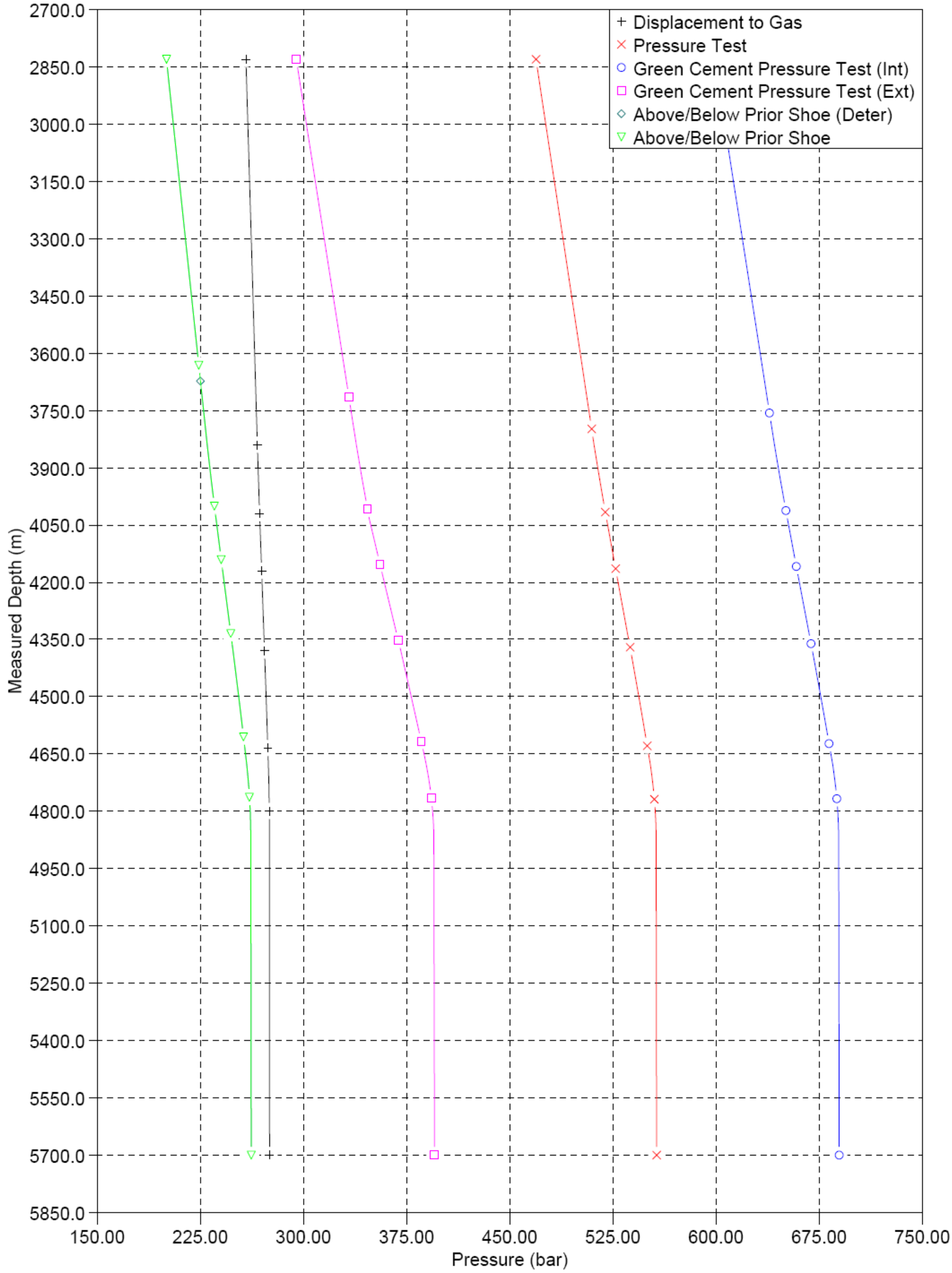
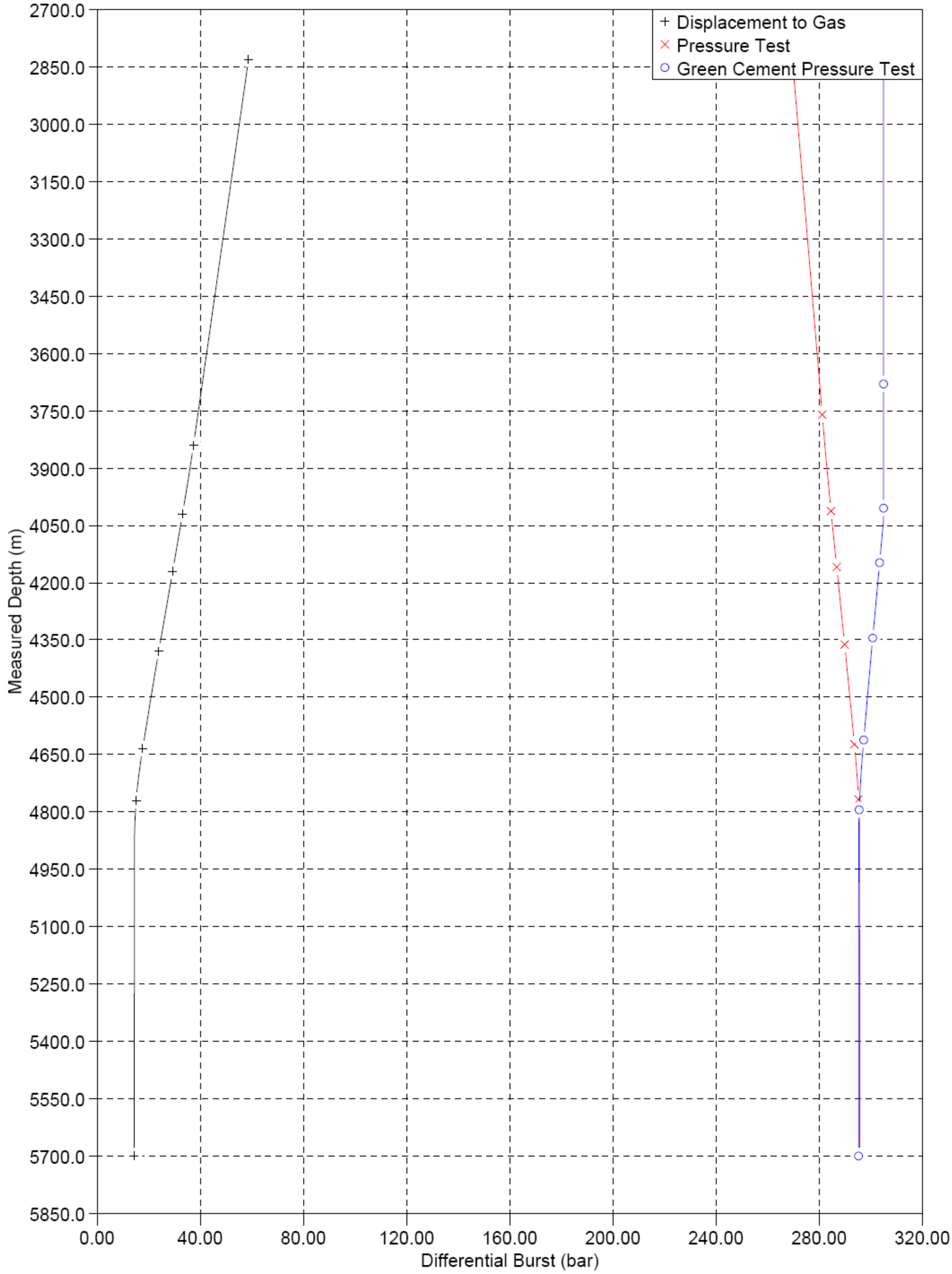


Figure B-3 Burst pressure profiles – 10 3/4” section



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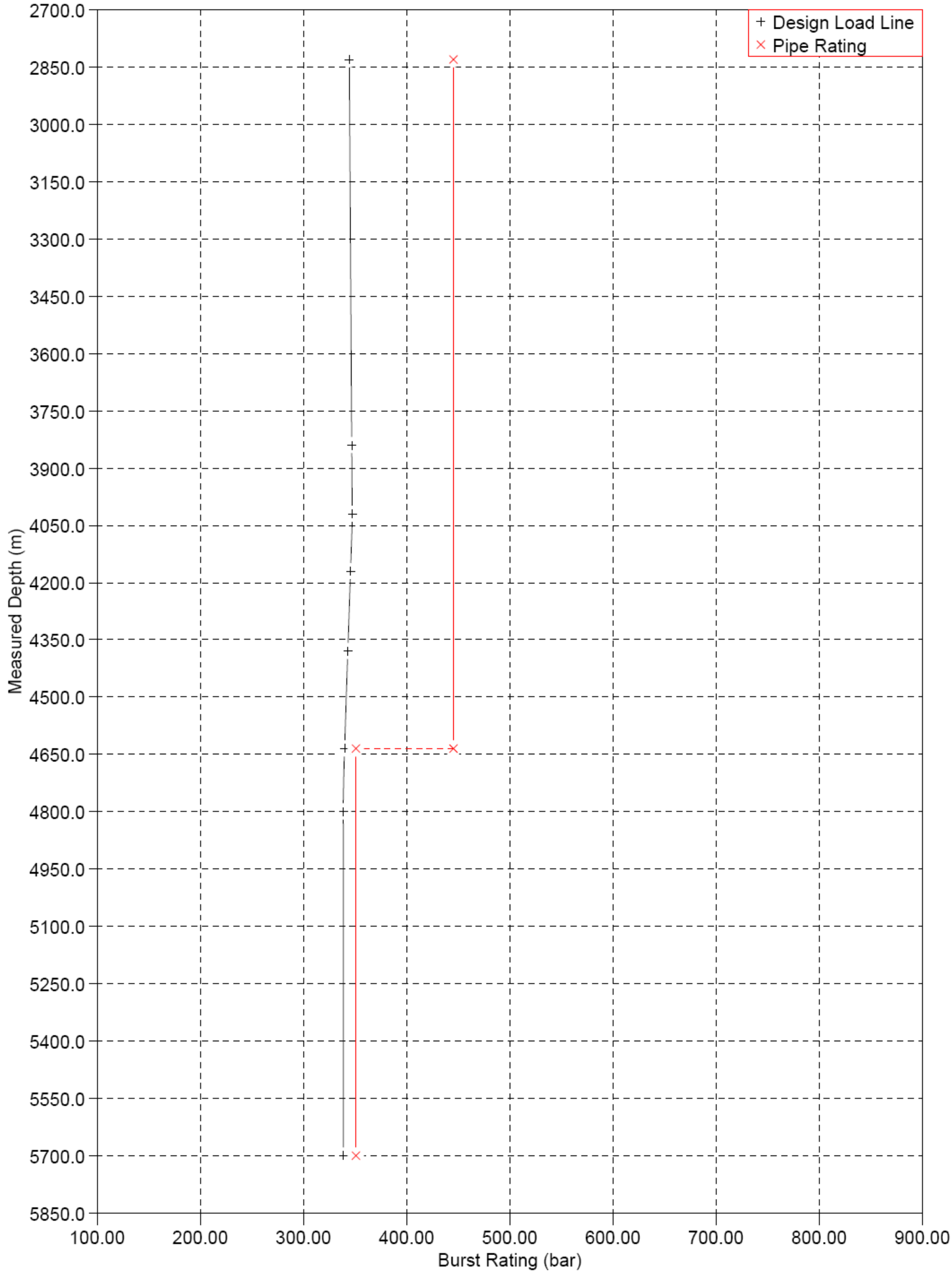

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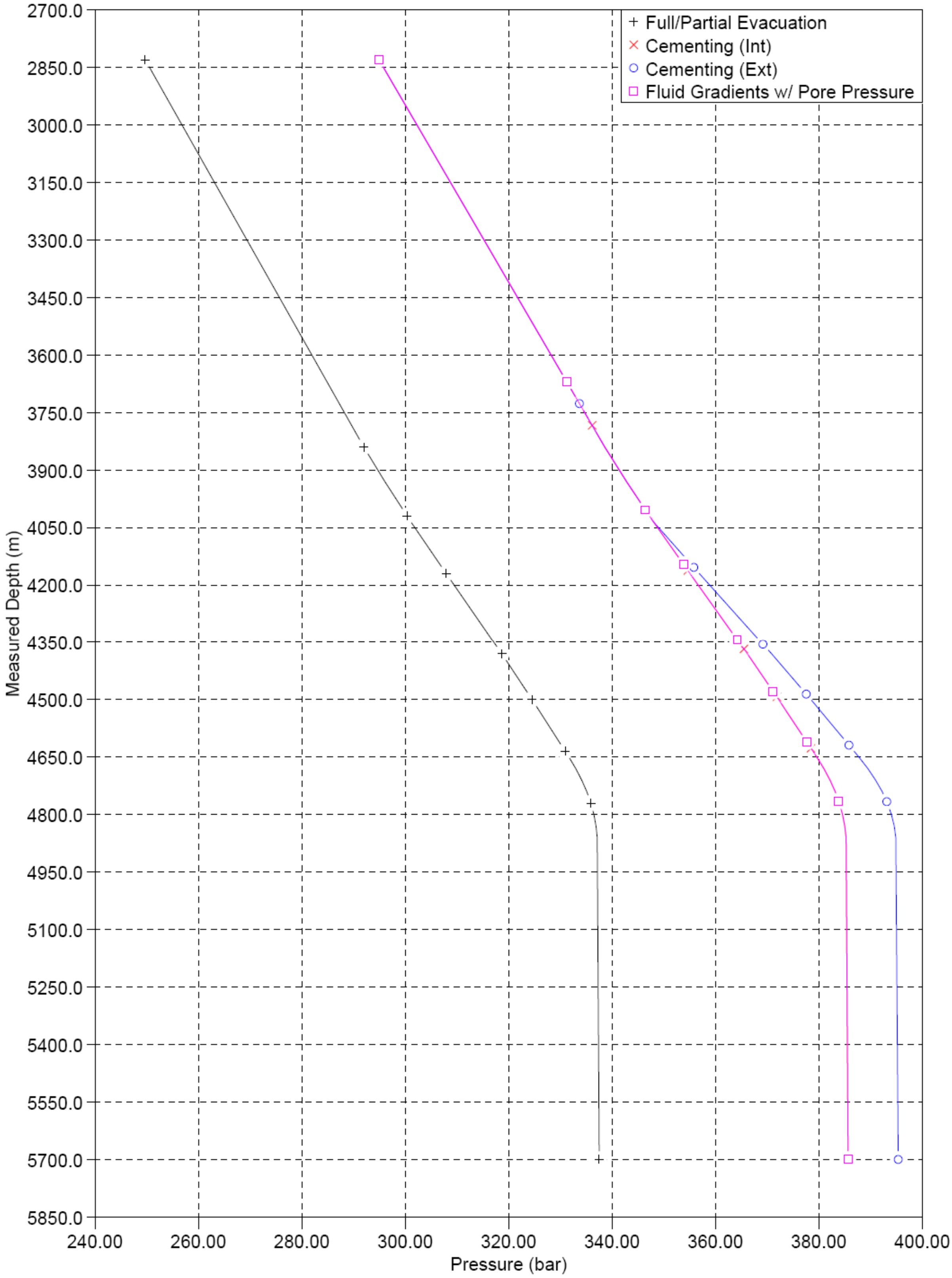

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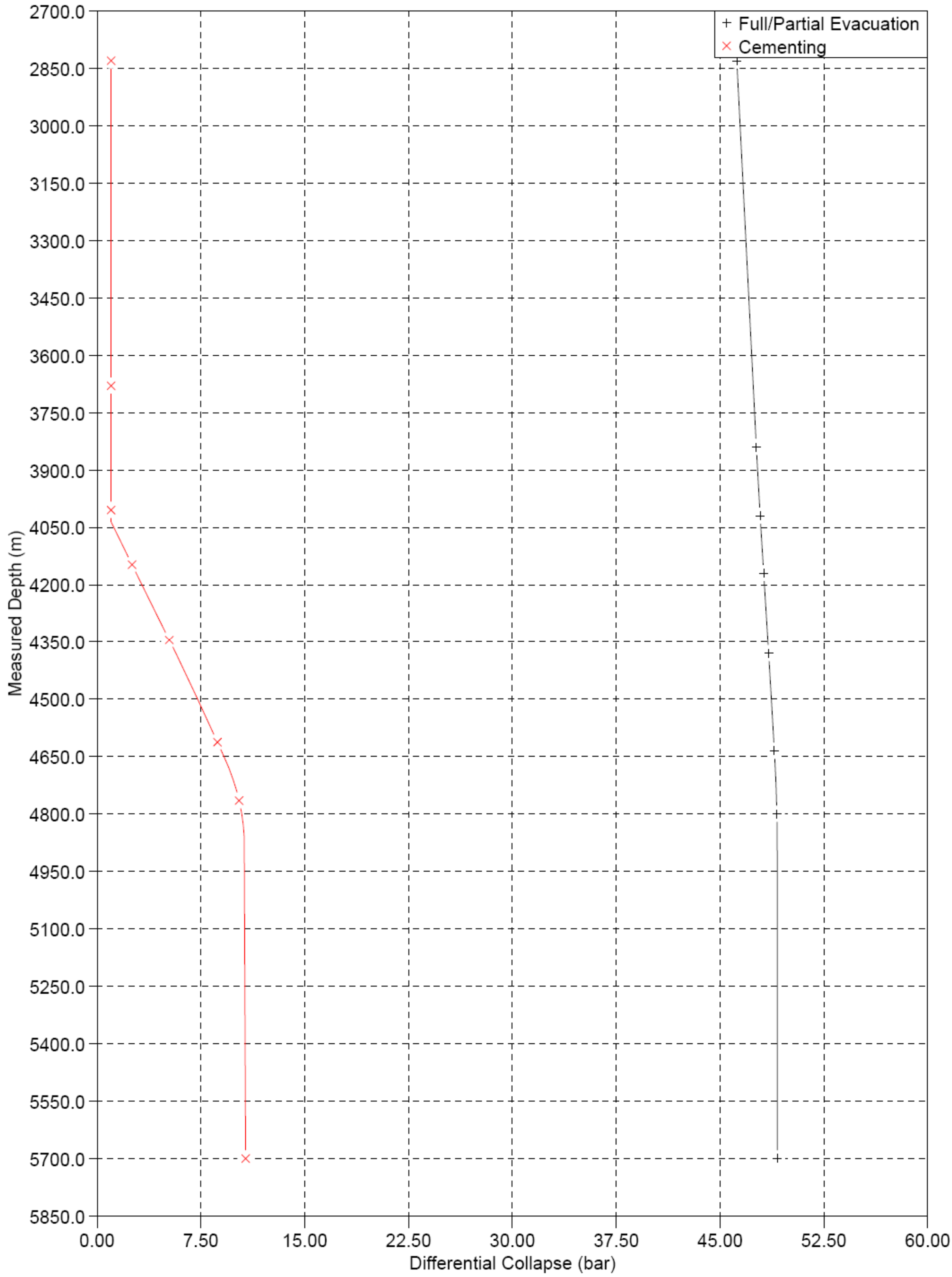

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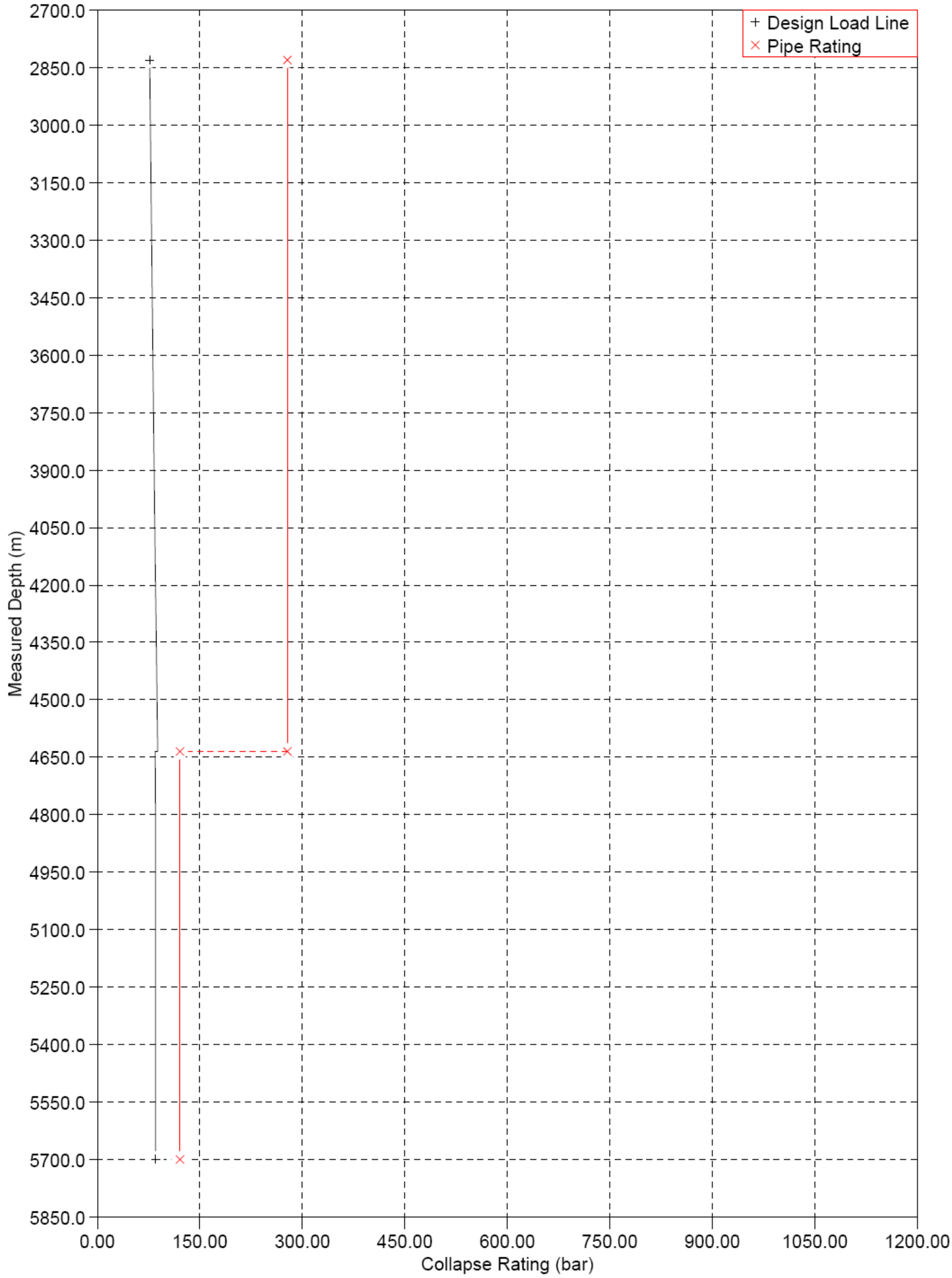

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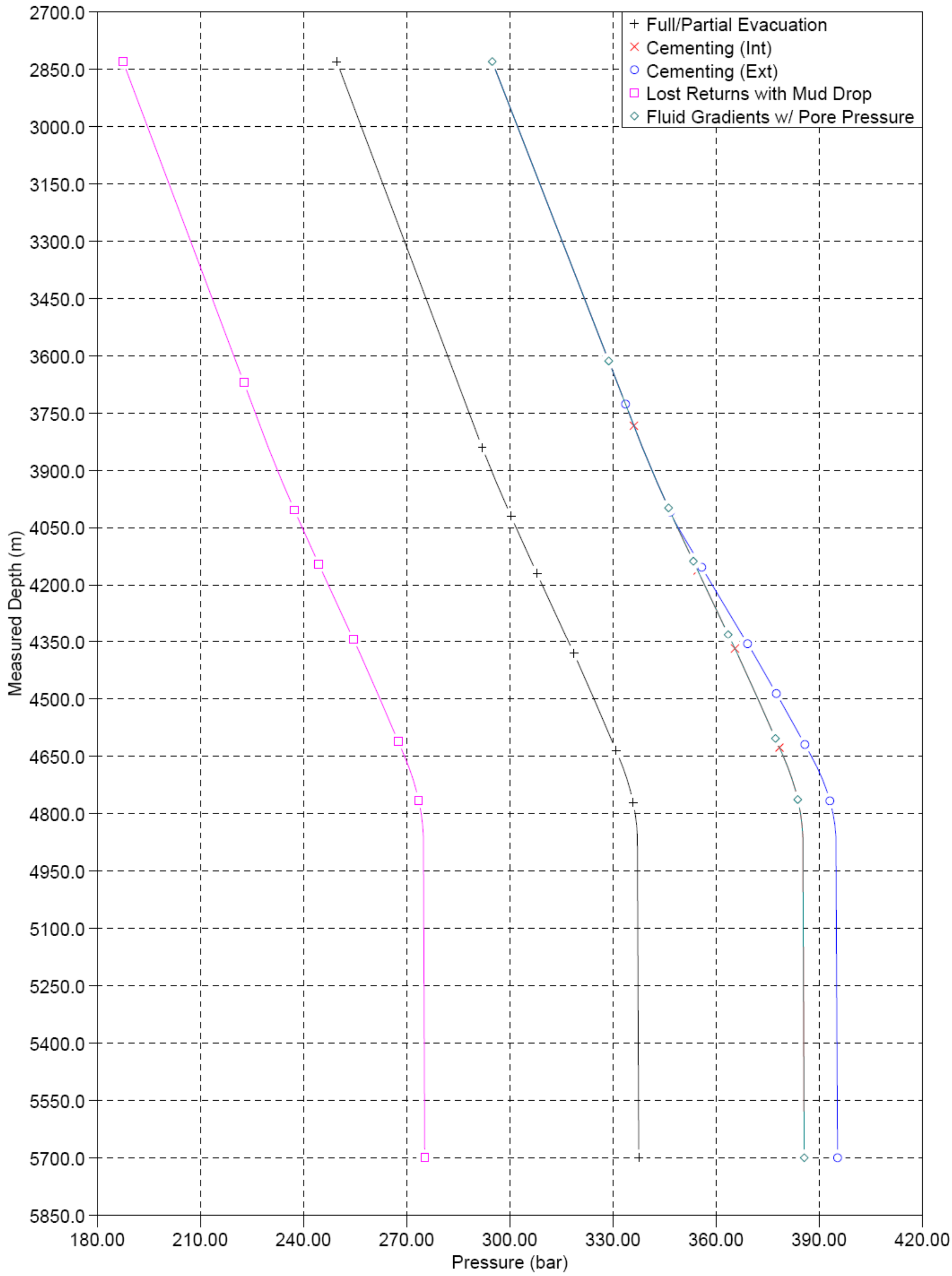

Figure B-9 Collapse pressure profiles including lost returns with mud drop - 10 3/4" section

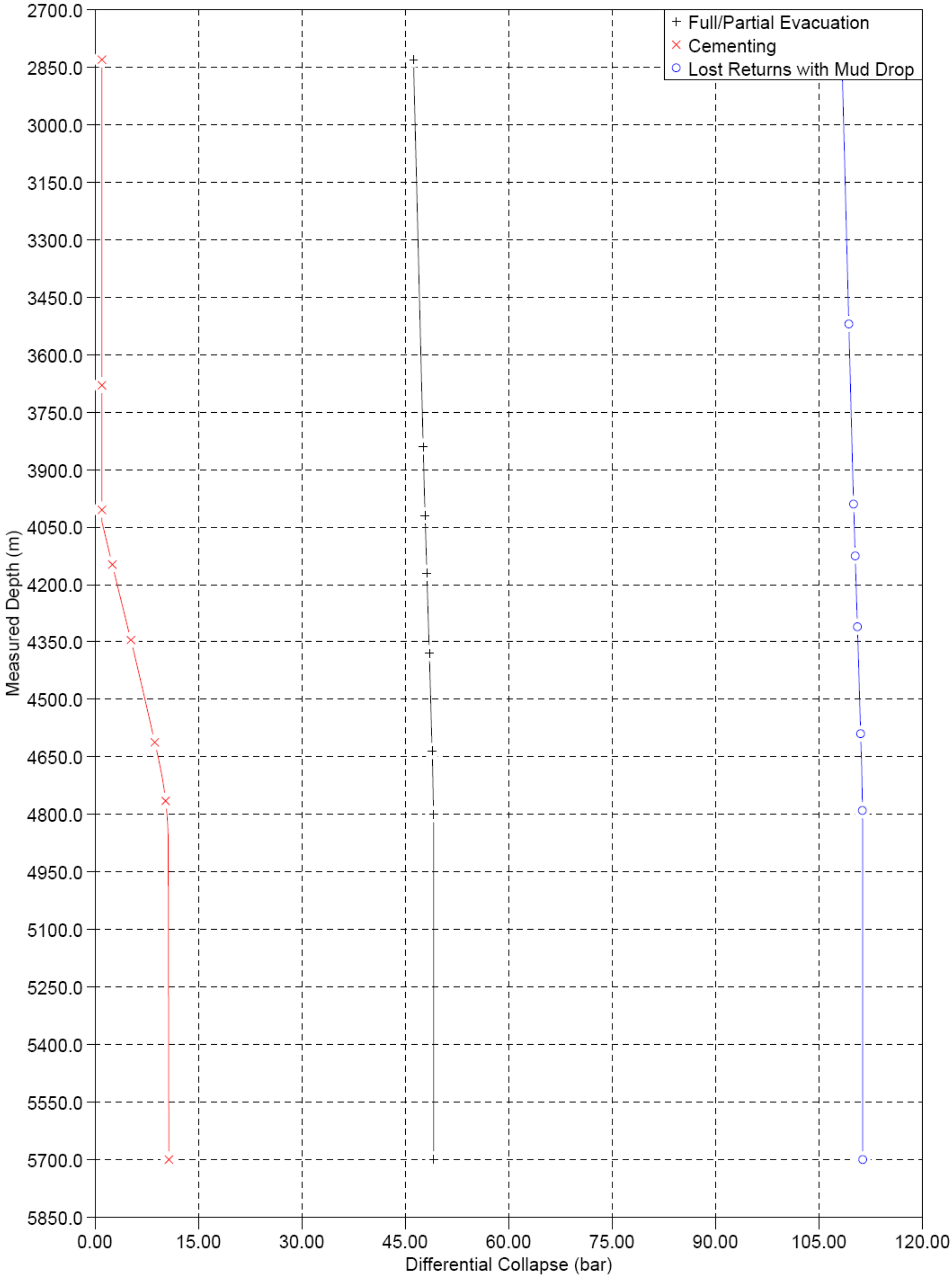

Figure B-10 Collapse differential pressure including lost returns with mud drop - 10 3/4" section

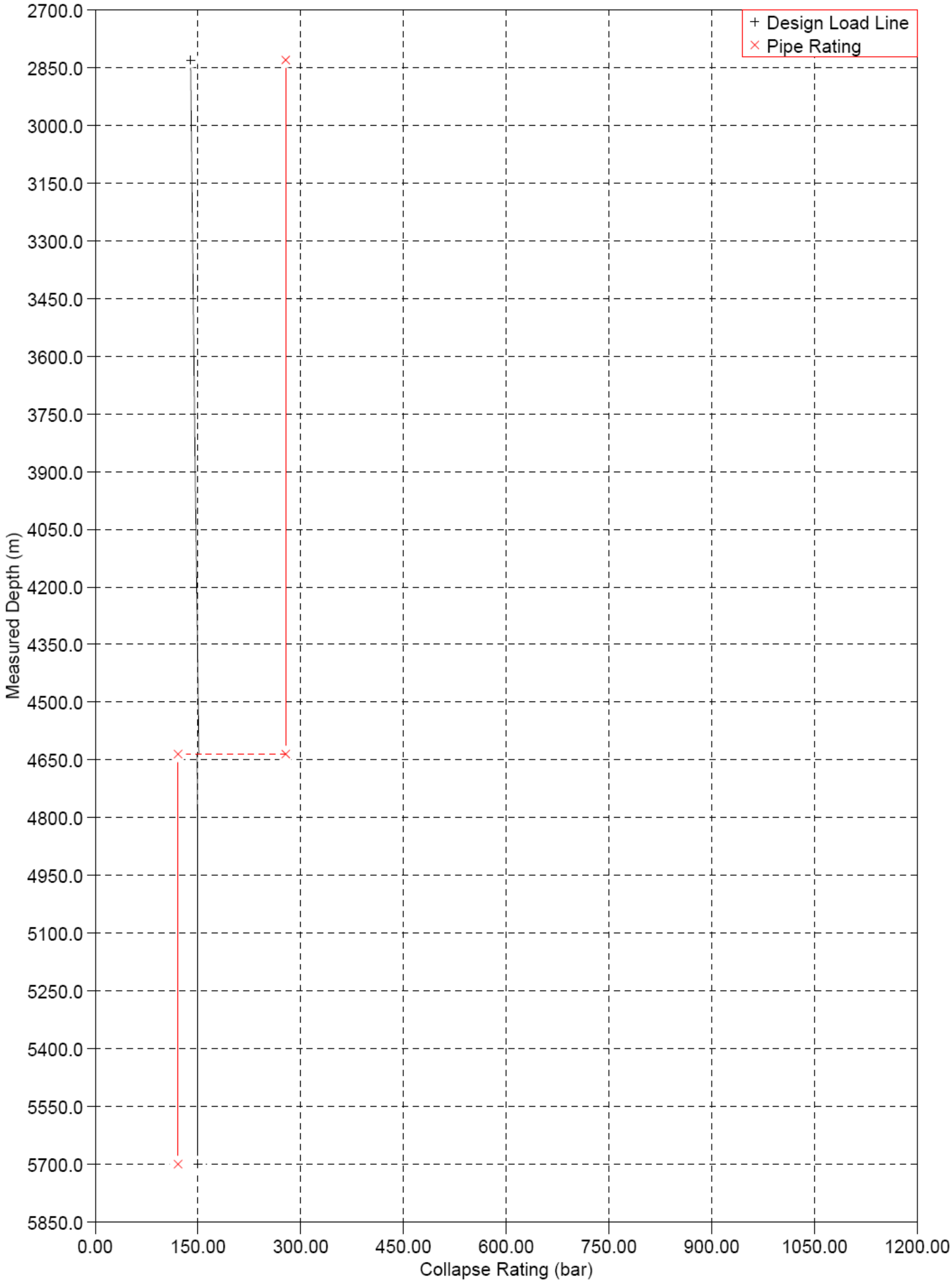

Figure B-11 Collapse design including lost returns with mud drop - 10 3/4" section