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Abstract

"Working Stress Design" is the most used casing design method and has been for many years, on the Norwegian continental shelf as well as all over the globe. It is a simple method which in essence comprises of calculating the differential pressure on a casing wall in given well conditions with regard to specific scenarios that can be expected to occur in the well. Every casing has its own strength with regard to burst, collapse and tension and by comparing this to the calculated load, a design factor is obtained which is required to surpass statutory safety factors imposed on the company by nations, the company itself, or by other regulatory agencies.
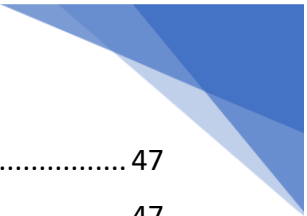
There exist fairly advanced casing design programs on the market which require a great amount of input variables and usually at a cost which equals their advanced nature. In this thesis a casing design program has been designed in excel with the main goal of being as simple as possible with as few as possible input variables needed, and still provide the user with the required load calculations as well as other relevant information. It has only one page where the user is needed to interact with the program, and it presents all the relevant results in one page. All the calculations and lookup functions are conducted in the background to only provide the user with the information needed. The program presents results on design factors, weak point in the well, full or reduced well integrity and kick margin values for each specific casing string or liner.

The program has been tested in case studies for two different wells obtained from the industry and has provided satisfactory results with regards to the mechanics of the program. Some limitations due to a different casing string setup in the second well has been identified and this provides an opportunity improve the program in order to handle non-standard or modernized casing string compositions.

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Nomenclature

API – American Petroleum Institute

BOP – Blowout Preventer

FG – Fracture gradient

ID – Inner Diameter

NCS – Norwegian Continental Shelf

OD – Outer Diameter

POOH – Pull Out Of Hole

PP – Pore Pressure

RIH – Run In Hole

SSC – Sulphide Stress Cracking

WBE – Well Barrier Element

WSG – Working Stress Design

lbs – Pound

psi – Pounds per square inch

ft – Feet

1 Introduction

There is a constant focus in the oil and gas industry on finding solutions and seeking opportunities to increase production while simultaneously decrease costs. This is a relationship that is difficult to balance, and especially with the increased focus on safety and environment that must also be implemented into the equation.

The drilling of a well is a costly affair, and it is estimated that the casing program represents approximately 15-35% of the total operation (Halal, Warling, & Wagner, 1996). Several new techniques and applications are tried out and tested these days, that strives to tackle this cost by changing the way we think about the design of a well. Some of these new innovations are casing while drilling which is reported to reduce cost and risk (Warren, Houtchens, & Tessari, 2006), dual gradient drilling that may reduce the number of different strings needed (Ziegler, Ashley, Malt, Stave, & Toftevag, 2013) and dual casing drilling that aims to drill a hole with two different diameters in one go. (Calderoni, Molaschi, & Sormani, 2011).

The aforementioned new techniques and methods are technical improvements, but there are also a lot of focus on earlier stages of the operation, which is optimizing software solutions to make planning more effective. In today's media a lot of focus in the oil and gas industry is directed towards the new trend which is "digitalization" which with enough focus can assist in increased cost savings and improvements in productivity. (Sylthe & Brewer, 2018). This also includes a focus on improving traditional approaches or designing new programs and applications that can assist in increased productivity, safety and in decreased cost.

1.1 Background

Well integrity has become a constant focus for operators around the world in the petroleum industry. Failure in wells is a costly affair and smarter and simpler ways of ensuring that wells are designed for full well integrity is needed.

Existing advanced casing design programs are hard to learn, so the motivation for this thesis is to make a simpler casing design program for calculating major loads expected during a well's lifetime

1.2 Objective

- Make a casing design optimization program using excel which presents a simple interface based on advanced calculations.
- The program must be as simple as possible in order to limit the amount of interaction needed from the user.

- The program should be able to tackle different casing string setups that may occur in the industry.
- The program must be as dynamic as possible, with as many automatic processes as possible to give the user a satisfactory experience.
- Some tests wells need to be obtained to be able to test the program properly with real well data.

1.3   Methods

The methods used for making the casing design optimization program is explained in detail in chapter 5.

1.4   Structure

The thesis starts off with an introduction by presenting Well Planning which gives an overview of several aspects involved in the design of a well and also indicates where in a well program the casing design is located. The next chapter is a theoretical approach to casing design where all the various aspects involved are presented to the reader. This is to establish a theoretical background on the subject prior to commencing on the next chapter that is working stress design. This chapter first introduces working stress design in a general way and then the focus is more directed on the working stress design specifically presented in Modern Well Design book (Aadnøy, 2010), which is the basis for the making of the Casing Design excel program. The next chapter is presenting the Casing design program to the reader. It's a walkthrough from start to finish on how to use the program and an explanation on all the calculations, formulas and functions that work in the background. The last chapter presents two case studies conducted on two separate real wells with the goal of testing the program as well as using it to evaluate the actual wells. The results are presented stepwise and discussions and proposed improvements to each well are located at the end of each case study. Lastly, a conclusion is presented to wrap up the findings of the case studies.

2 Well planning

The designing of a well is one of the more demanding aspects of a drilling engineer's tasks and is a very important part of the entire life of a well. A collaboration between several engineering principles is needed, and experience is an important factor, to ensure that the whole well planning process is done according to regulations and set requirements from the company as well as the local authorities.
There are many different well philosophies in the industry, corporate as well as personal, regarding how to plan and design a well, but some common interests and practices are fundamental, such as minimum cost, safety, and of course that the result is a usable well. Success in these objectives are much reliant on several parameters, such as equipment used for drilling, temperature and size of the hole, geological parameters, Limitations of casings, and budget, among others.

As in many areas of daily life, safety should be given the highest priority, where top focus should be personnel safety. History has shown that this can't be stressed enough, and due to lack of focus on HSE both in planning and execution has caused many incidents with serious outcomes and fatalities. The second priority when it comes to safety is well integrity. This is where the well design is crucial. A well design must be designed in a way to ensure well integrity, and if designed correctly, will be able to tackle abnormal and unforeseen well conditions and events.

The complete planning of a well is very extensive, involving aspects such as objectives for the well, consents from the relevant authorities and collection of data. Then preparation of drilling programs, choosing of rig specification and equipment, as well as cost estimates and much more. (Robert F Mitchell, 2007) There are many topics including in the planning of a well, one of them is related more to the design of the well, which involves many processes, some of which must be designed prior to others for practical reasons. The below flowchart gives an overview of the processes that may be involved in the design.
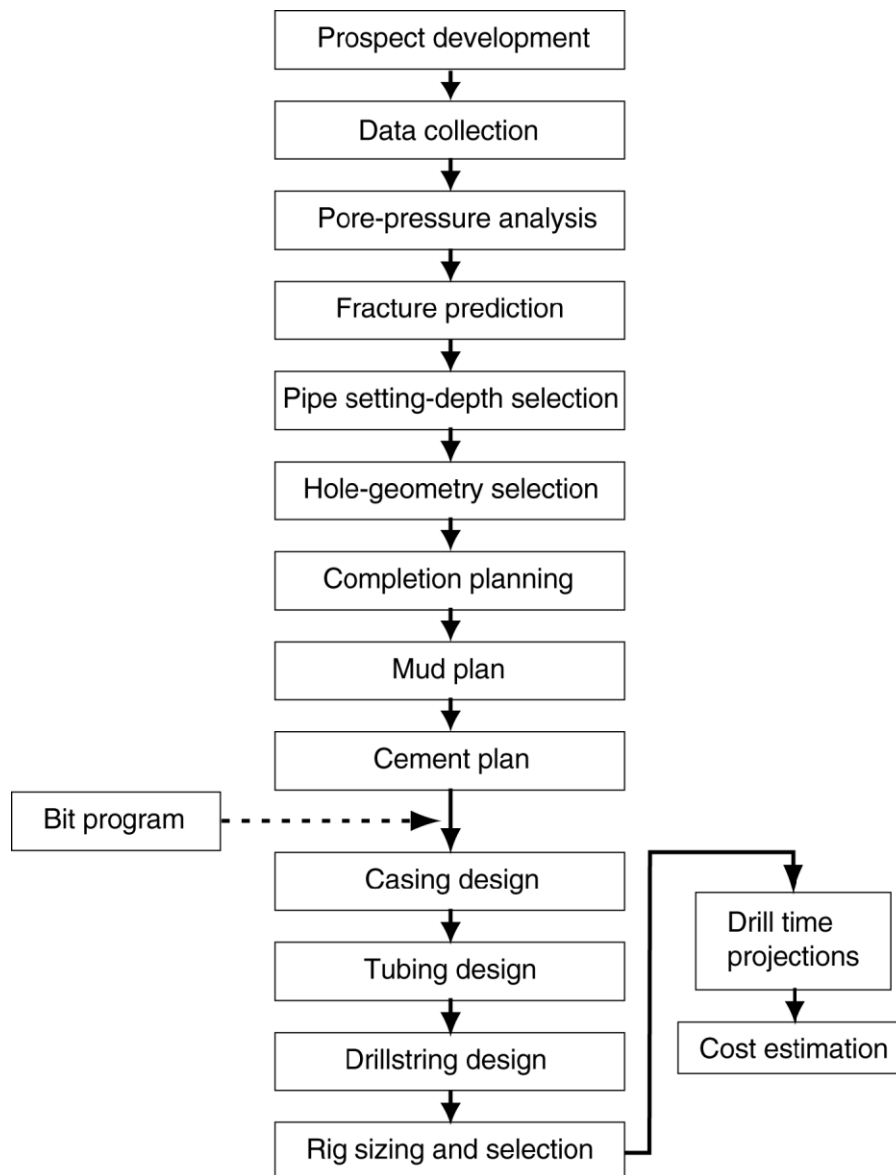
Figure 1: Well planning flowchart (Robert F Mitchell, 2007)

When it has been decided that the well will be drilled, after all data has been analyzed and confirmed, the program has been commercially approved, and the various design programs has been specified, the well can be added to the company's activity plan. This is a process that follows a systematic approach where the well is drilled in sections, cased off and cemented, before continuing with the next section. The normal approach to this is by starting with a conductor, which is placed in the seabed, then a surface casing, followed by one or more intermediate casings, and lastly the production casing and/or liner. These are all usually hung off inside the wellhead. When drilling is complete and if it is to be a producer/injector, a production tubing will be installed within the production casing which will be the main pathway for produced/injected fluids. A BOP has been installed during the drilling operation and is replaced by a Xmas tree at the end of the operation for production to start. This is an example of a setup, other configurations exist, such as tie back liners and intermediate liners, as well as new approaches emerging frequently.
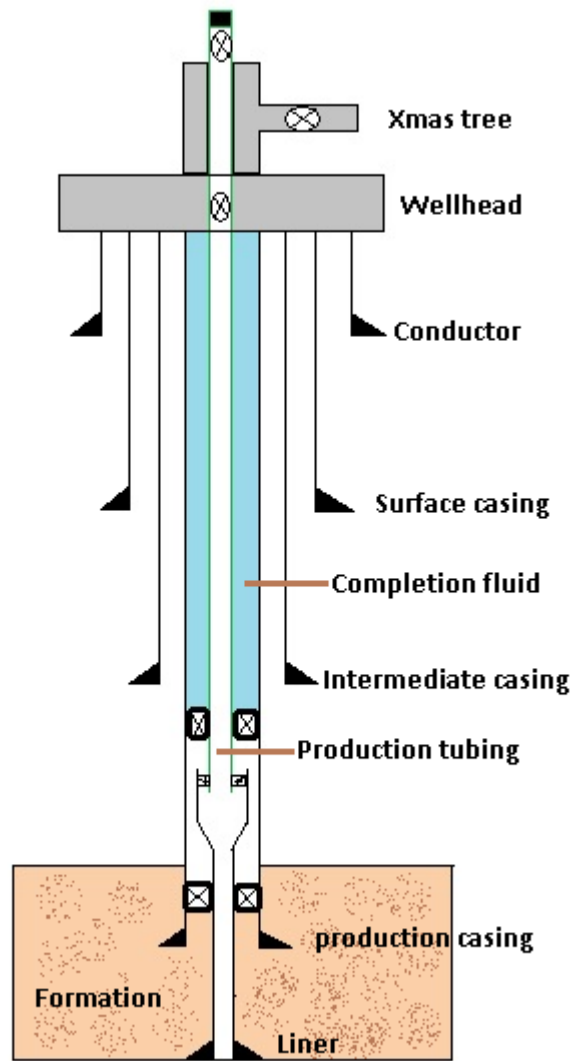
Figure 2: Illustration of a completed well.

The above figure shows an example of a completed well. This thesis will be focusing on the casing design part of the well design and well planning, and all the factors that is accompanied with casing.

3 Casing Design

As seen in figure 1, the "casing design" is one of the major activities in the planning and design of a well, and a very important one. It is the largest structural component and is there to maintain stability of the borehole and act as a barrier between the formation and the well. It is also one of the largest portions of a drilling project with regard to cost. Because of this, the planning of casing setting depth and which types of casings to use is of the outmost importance when constructing a safe and effective well. Some of the functions of the casing string itself can be summarized as this: (Prassl, 2000)

➢ To isolate various porous zones downwards in the wellbore to prevent contamination of the pay zone
➢ To prevent drilling mud contamination of near surface fresh zones.
➢ Protect hole from cave in.
➢ To Provide support and connection of wellhead and wellhead equipment.
➢ To provide engineers with exact hole dimension, which makes completion, testing and intervention much simpler.

There are a huge number of different casings on the market, with different strength ratings, composition of metals, and for various applications in the industry. The casing strength is measured and rated by how it is affected by burst, collapse and tensional loads, as well as biaxial forces and triaxial forces (Aadnøy, 2010). It must also be able to withstand pressures related to completion, RIH, and corrosive influences. In the design of a well, time is an important factor because it is going to be around for a while, depending on the reserves and the technology. Consequently, when designing each casing string it is important to design it so that well Integrity is achieved for the whole duration of the well, with added safety window. An optimal casing string is one designed from the inside out. This means that to ensure an optimized production over the life of the well, the engineer starts with looking at what size is needed on the inner casing/tubing, and then calculates casing sizes outwards based on this (Azar, 2007).

The geophysical basis for the casing design is fracture- and pore pressure. Data for this is not exact when it comes to exploration drilling, because of limited offset well information, but when new wells are developed, data from existing wells will be used to design the casing strings. The plot below illustrates how the pressure gradients may look in a well.
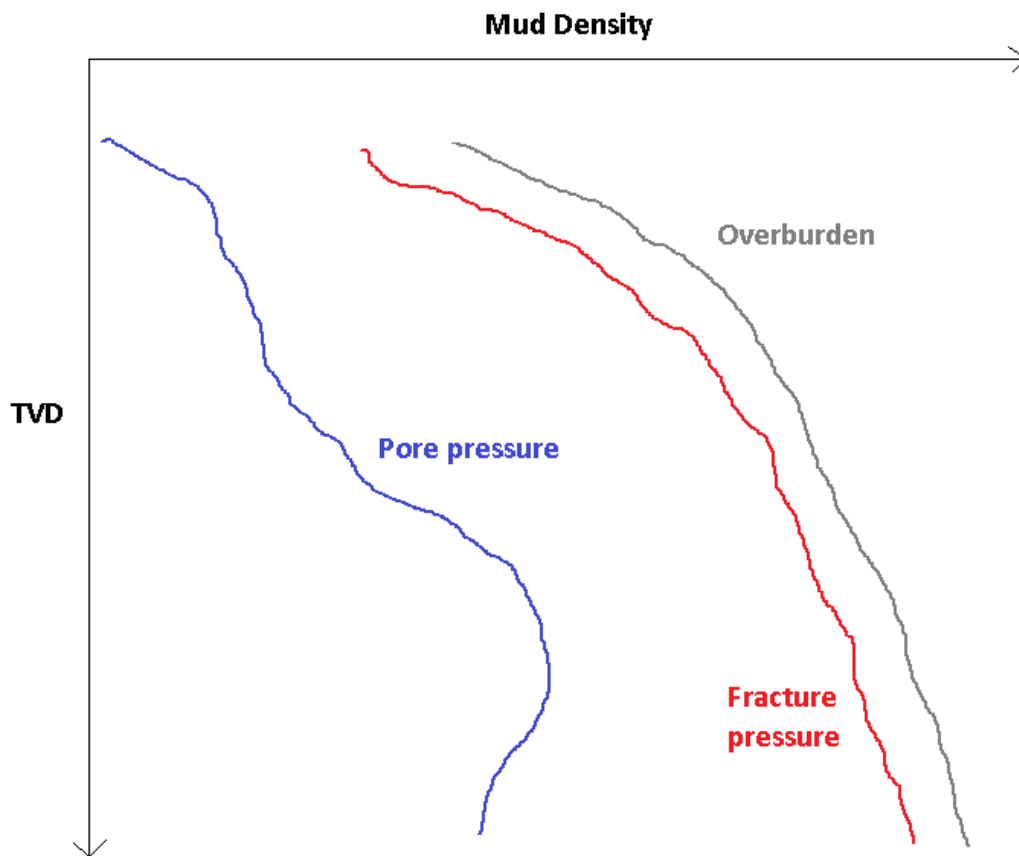
Figure 3: Pressure gradient plot

The casing design process is a process that is based on using the cheapest casing strings that can withstand expected loads over the planned lifetime of the well. In addition to verifying the casing strings, there are also requirements to verify the integrity of connections, circulating devices, and landing string (NORSOK, 2013) as well as identifying the weakest point in the string when it comes to loads (Aadnøy, 2010). These loads will be explained thoroughly later in the thesis. According to (Prassl, 2000) the well casing design itself should be based on these sets of data:

➢ Loads that can be expected to affect the casing and downhole equipment throughout the lifetime of the well. These loads come from the drilling operation, completion and intervention operations, testing, injection, and production.
➢ The pore pressure of the formation vs the expected fracture pressure.
➢ Cost and availability of the different casings.
➢ Expected lifetime from production start.

(Azar, 2007) lists four principal steps for the effective design of a casing string:

1. Length and size needed for the well to reach its full production potential.
2. Calculation of the various pressure loads expected from the different operations, such as secondary recovery, stimulation and thermal application.

3. Identify any corrosive environment that will directly affect the casings in the well's lifetime and based on this, select an alloy designed to resist this corrosion. Alternatively, design an alternate system to control the corrosion.
4. The casing will in its lifetime probably be subjected to mechanical, chemical and hydraulic forces and therefore the correct grading and weight must be chosen.

3.1 Casing Clearance

The size of the hole and minimum casing clearance depends on several factors but as Aadnøy stated they are always governed by the connector/coupling configuration (Aadnøy, 2010). Stronger couplings may result in a larger outer diameter on the string, which in turn results in a narrower window for the annular space. The *necessary* clearance on the other hand depends on the mud condition according to "Drilling Engineering" by J.Azar (Azar, 2007). He states that in cases where a lightweight mud is used in competent formation, 1 ½" total clearance is sufficient. This can affect the cementing operation and result in a high cementing back pressure. It is therefore recommended a clearance in the area of 2-3 in. (Azar, 2007). The clearance/space between each casing, and between casing and tubing is called an annulus. The volume outside the production tubing is the A annulus, and outside the production casing is the B annulus and so forth.

3.2 Types of Casing

Table 1 presents some of the common casing sizes used on the NCS alongside some other known sizes in use

Table 1: Typical casing design on the NCS.

Standard casing types	Hole size In	Diamater OD in	Other sizes used in
Conductor casing	36"	30"	
Surface casing	26"	20"	18 5/8"
Intermediate casing	17 ½"	13 3/8"	16"
Production casing	12 ¼"	9 5/8"	10 3/4"
Production liner	8 ½"	7"	5 1/2"

3.2.1 Conductor

The first casing to be run in the well is the conductor. This is usually a very large diameter pipe and its primary purpose onshore is to act as a flowline, for mud to return to the pits, as well as a stabilizer for the upper part of the hole. (Azar, 2007). The conductor is also part of the foundation for the installation of the BOP, as well as a functioning support for the surface casing and the wellhead. Some of the requirements for the subsea conductor is to isolate unconsolidated layers below the seabed as well as being deep enough, with the proper strength, to withstand shallow gas situations should they emerge. The diameter of

the conductor should be of a fitting size for it to be able to house the surface casing and being able to displace cement efficiently, in addition to being installable by the rotary table.(Aadnøy, 2010).

3.2.2 Surface casing

Traditionally, after the conductor has been placed, the next hole will be drilled through it. This is a smaller diameter hole which will house the surface casing. Its function is to isolate the weaker formations in the well down to the point where the formation integrity is sufficient for proper control concerning pressured formations further down in the hole, as well as isolation of potential shallow gas zones to ensure well integrity before further drilling can commence. As with the conductor, surface casing is also there to protect the subsequent casings from corrosion and to be a support for the wellhead and BOP. (Aadnøy, 2010).

3.2.3 Intermediate casing

Its purpose is to isolate the different formations up to the surface casing shoe. This is so that the next open hole section can be drilled in a safe manner down and through the pay zone. The intermediate casing can be one or more casing strings depending on depth and on the formations encountered, may it be weak zones, pressurized zones or general unstable zones. If more than one string is planned, it is important to ensure that the inner casing placed in the pay zone will have a diameter big enough for production. (Aadnøy, 2010). This is where the principle of designing the well from the inner casing and out proves its importance.

3.2.4 Intermediate liner

In the case that the hole condition demands an isolation of a section of the well, an intermediate liner can be installed and set between two casing strings. This is also done to save material costs because the liners don't reach all the way to the surface but is rather hung off on a liner hanger on previous casing string. Most commonly this liner hanger is placed 15-200m up the previous string section to ensure a tight seal is maintained. Bottom overlap to next string is also ensured to be of sufficient length for a tight seal. It will not reduce casing strings needed because it will function just as another string.

3.2.5 Production casing

The production casing has the objective of isolating the production/injection zones, also called the pay zones, which is where the hydrocarbons are. It is also in place to make sure that the annulus over the production zones is properly cemented so that the fluid does not migrate up or down the wellbore. It is designed to protect the environment should the production tubing experience a failure. A tubing failure can result in a shut in well which means that the production casing should be designed to withstand a shut-in wellhead pressure, as well as being able to withstand and contain the full BHP and any mud or workover fluids should the tubing packer need replacing or removal. In addition to all these

factors, it must also be designed to withstand wear from time, like mechanical and chemical wear.

3.2.6 Production liner

In cases where a production casing is not used or doesn't go further than to the top of the reservoir, a production liner may be used to isolate the productive zones instead. The liners can be regarded as shorter production casings and will therefore have to be designed as such when it comes to integrity of the well. Cost may also be the foundation for a decision to use a production liner instead of casing, for instance in wells with lower pressures. It reduces need for steel and steel costs money.

3.2.7 Tieback casing

A tieback liner is a string that is stabbed into a mechanical sealing assembly in a hanger to make a seal. To prevent leakage from the formation, the liner is cemented onto the casing. To ensure a good seal there is a significant overlap of the liner and casing. The tieback casing is designed to the same conditions as a production liner, without the presence of axial load from testing. A tieback casing can be using for a number of reasons, some of which helps increase pressure integrity in the well and resistance towards gases that may be expected, like CO_2 and H_2S.

3.3 Tubing

When all the casing strings are installed in the well, or at least the ones that are considered needed the particular operation, the well is handed over to production and a production tubing is installed. The tubing is there to transport the produced fluid from the reservoir and up to the surface. Or to the seabed if it is part of a subsea installation. By using a tubing, we protect the production casing from corrosion and erosion as a result of flowing fluids. It is set in place using a downhole production packer, which has a main objective of sealing of the A annulus. If this is a single reservoir well the annulus will most likely be filled with completion fluid, but in the case of multiple reservoir zones this annular space can be used as a conduit for produced fluids (Bellarby, 2009). The tubing is typically made of steel like the casing string and must also be designed to withstand expected loads during its lifetime. Although, if a tubing is wearing down it can simply be pulled and replaced by a new one, contrary to a cemented casing, which would require a bigger and more costly operation. The tubing is hung in a tubing hanger in the wellhead in cases where a horizontal Xmas tree is used, and it is hung in the Xmas tree itself should it be a vertical tree.

3.4 Casing Properties

Casing is made of steel and steel is an alloy consisting mainly of iron, with the addition of carbon in amounts of 0.2% to 2.1%, depending on properties wanted in the finished product.

Other common alloying materials used in steel is tungsten, chromium and manganese. Strength of the casing can also be increased by tempering. Casing used in the oil and gas industry is almost without exception made of a 0.3% carbon steel with the addition of small quantities of manganese (Robert F Mitchell, 2007). Casing are usually classified either to API standards or non-API standards.

3.4.1   API classification

API, short for the American Petroleum Institute, has formed a set of internationally accepted standards for casing and tubulars used in the oil and gas industry. The classification of casing is based on 5 properties according to (Mian, 1992):

- Steel grade
- OD
- Joint types
- Length range
- Unit weight (wall thickness)

The classification system is based on strength characteristics of the casing, where a letter code is introduced at the start of the name to identify the grade followed by a number to inform us of the yield strength of the steel. This number is in thousands of psi.

Table 2: Examples of API steel grades

API Grade	Yield Stress, psi		Minimum Ult. Tensile, psi	Minimum Elongation, %
	Minimum	Maximum		
H-40	40.000	80.000	60.000	29,5
J-55	55.000	80.000	75.000	24,0
K-55	55.000	80.000	95.000	19,5
N-80	80.000	110.000	100.000	18,5
L-80	80.000	95.000	95.000	19,5
C-90	90.000	105.000	100.000	18,5
C-95	95.000	110.000	105.000	18,5
T-95	95.000	110.000	105.000	18,0
P-110	110.000	140.000	125.000	15,0
Q-125	125.000	150.000	135.000	18,0

The table above shows a selection of API graded steel casing. The value of yield strength listed here is defined as tensile stress that would be required to elongate the material to 0.5% to that of the total length. This is true for all the casings except for P-110 which has a tensile stress listed to elongate the material 0.6% (Robert F Mitchell, 2007).

3.4.2   Non-API classification

There is casing in use around the globe that do not conform to the general API standards. These are usually casing designed for a very specific set of parameters, often stronger and

with a high resistance to corrosive environments. An example of this is the casing developed for the Kristin field to combat HPHT challenges like sulphide stress cracking, where vanadium was added as an alloy, and the steel was tempered at a higher temperature. (Nice, Øksenvåg, Eiane, Ueda, & Loulergue, 2005). Table 3 below shows a list of commonly used non-API grades.

Table 3: Examples of non-API steel grades

non-API Grade	Manufacturers	Yield Stress, psi		Minimum Ult. Tensile, psi	Minimum Elongation, %
		Minimum	Maximum		
S-80	Lone Star	75.000	-	75.000	20,0
	Longitudinal	55.000	-	-	-
modN-80	Mannesmann	80.000	95.000	100.000	24,0
C-90	Mannesmann	90.000	105.000	120.000	26,0
SS-95	Lone Star	95.000	-	95.000	18,0
	Longitudinal	75.000	-	-	-
SOO-95	Mannesmann	95.000	110.000	110.000	20,0
S-95	Lone Star	95.000	-	110.000	16,0
	Longitudinal	92.000	-	-	-
SOO-125	Mannesmann	125.000	150.000	135.000	18,0
SOO-140	Mannesmann	140.000	165.000	150.000	18,0
V-150	U.S. Steel	150.000	180.000	160.000	14,0
SOO-155	Mannesmann	155.000	180.000	165.000	20,0

3.5   Casing setting depth selection

A basis for casing setting depth determination should be to conduct the drilling of the next open hole section in a safe manner to ensure success without incidents. To make sure that this is maintained, several aspects needs to be considered, such as lithology of the wellbore, over pressurized zones, the existence of shallow gas, potential for lost circulation and troublesome zones in general. (Santos, Adasani, Azar, & Escorihuela, 1995). Conventionally the shoe setting depth calculation is dominated by pore pressure and fracture pressure of the formation as well as the kick margin concept. Furthermore, it is important that the formation health at the target depth is evaluated to ensure that the casing shoe is set is a competent formation that can withstand the high pressures and loads associated with kicks. An example to reduce the chance of formation damage and collapse is to set the shoe in shale formation which usually can be regarded as competent, unlike sand formation. The first pipe to be installed is the conductor and it should be placed at such a depth that there will be no fracture of the formation when drilling the next open hole section. There should not be any presence of hydrocarbons in the shallow parts where the conductor will be installed, but there is always a possibility to encounter shallow gas pockets. For the surface casing, ensuring that the next open hole can be drilled without fracture is also a criterion,

but this casing shoe must be set at a certain depth so that it is able to withstand a kick, should it occur. The same goes for all the following casing and liners. (Aadnøy, 2010).

To determine the maximum length that should be drilled as an open hole section, a relationship between the fracture and pore pressure has been developed by Aadnøy (Aadnøy, 2010). As mentioned earlier the well can be designed from top to bottom or the other way around, from bottom to top. The bottom to top principle is the most commonly used method and it works by starting with setting depth of the production casing and working upwards until determining seat for the conductor. This ensures that the number of pipes utilized is kept at a minimum while maintaining integrity (Aadnøy, 2010). The production casing setting depth is often just above the reservoir, with the liner extended into the reservoir.

The simplest and most common case for determining the setting depth is by adjusting the mud density so that it stays between the pore and frac pressures. This is to avoid fracturing the formation and to avoid influx of formation material.

Table 4: Example of setting depths based on mud weight

Casing size (inch)	Depth (m)	Mud weight (s.g.)
7	2700	1,60
9 5/8	2400	1,60
13 3/8	1300	1,30
18 5/8	700	1,20
30	400	1,03

This simple way based on mud weight is applicable when drilling onshore wells or on fixed installations offshore but if the drilling is conducted through a riser from a semi-submersible rig or from a drillship, the riser margin should be taken into account (Aadnøy, 2010). This is due to the pressure effect that is applied from the drilling mud in the part of the riser that extends above sea level and up to the drillfloor. Should the riser have to be disconnected for any reason, like bad weather or another emergency, this effect is lost and should therefore already be considered in the design process for the setting depths. The mud inside the marine riser is replaced by a seawater gradient as well.

When the casing setting depths have been determined an evaluation of kick margins should always be conducted for each interval of open hole below the surface casing, as well as checking the availability of the various casing that has been selected in the design. Should one of the casing types selected prove to not be available, it could lead to a re-evaluation of the design or to choose a more expensive higher graded casing instead. A new approach to casing setting depth using combined criteria is explained in detail in the following paper (Aadnoy, Kaarstad, & Belayneh, 2012)

3.6 Well Barrier Elements

The standard for well integrity in drilling and well operations on the Norwegian continental shelf, NORSOK D-010, defines Well Integrity as: *"Application of technical, operational and organized solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well" (NORSOK, 2013).* This standards goal is to replace companies' individual specifications and guidelines in future petroleum developments as well as in existing ones. To prevent the uncontrolled release of said well fluids the standard always requires two barriers to be present in the well. Should one barrier fail, the other is designed to withstand the failure until a second barrier can be reinstated. The standard lists primary and secondary barriers for a huge variety of wells in all shapes and forms, and at different times in the well's life cycle, from drilling activities through completion and to interventions and workovers.

Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	n/a after initial verification
Liner cement (top reservoir to production casing shoe)	22	n/a after initial verification
Casing (production liner)	2	n/a after initial verification
Liner hanger packer	7	n/a after initial verification
Casing (between production packer and liner hanger packer)	2	n/a after initial verification
Production packer	7	Continuous pressure monitoring of A-annulus
Completion string	25	Continuous pressure monitoring of A-annulus
DHSV / control line	8	Periodic leak testing. AC DHSV: xx bar/xx min.
Secondary well barrier		
In-situ formation	51	n/a after initial verification
Production casing cement (above production packer)	22	daily monitoring of the B-Annulus
Production casing (above production packer)	2	Continuous pressure monitoring of A-annulus
Production casing hanger with seal assembly	5	Continuous pressure monitoring of A-annulus
Tubing hanger (seals)	10	Continuous pressure monitoring of A-annulus
Wellhead (WH/tree connector)	5	Continuous pressure monitoring of A-annulus
Subsea tree	31	Periodic leak testing of valves AC: xx bar/xx min.

Figure 4: Subsea production well with a vertical tree (NORSOK, 2013)

The image above is taken from the standard and it shows a subsea well with a vertical Christmas tree installed and it lists the primary and secondary WBE (Well barrier elements)

for this type of well. Here we can see that for this production well the production liner and the tubing is main WBE's and the production casing and cement is secondary WBE's

3.7 Well Integrity

It is of the outmost importance that the well can withstand abnormal events that may arise during drilling. Two of the most important non-routine events that may occur during drilling is loss of mud returns and taking a high pressure kick. (Aadnøy, 2010). Should we lose circulation it will most likely result in a stop of the operation in order to fix the problem. First the loss zone will have to identified and then fixed by either cementing off the area or plugging it with LCM, which is a material containing fibers and/or other larger objects that will plug fractures in the formation. This process involves a lot of planning regarding LCM selection (Whitfill, 2008). Regarding casing design, circulation losses will result in an increased collapse load on the casing.

If we during drilling come across a gas pocket, a kick may arise. These pockets are usually unforeseen and if the mud and well pressures are not designed to handle this it can result in costly and dangerous situations. An analysis conducted in the 90s on drilling kick statistics from thousands of wells (Wylie & Visram, 1990), showed that that the major cause of kicks has been the failure to keep the hole full (i.e. lost circulation), and the second cause has been drilling with a mud that has inadequate density for the well. Regarding casing design, these events will not lead to much load on the casing as long as the well is open, but should the well be shut-in containing gas, fully or partially, a significant pressure may arise on the casing in the shallower parts of the well. (Aadnøy, 2010).

From a casing design point of view, Aadnøy defines well integrity as either full or partial/reduced. Three scenarios will be described involving a gas filled well that is shut in.

- ➢ Full well integrity: The casing and the open hole can both handle a gas filled well.
- ➢ Reduced well integrity: Casing can handle it; open hole cannot.
- ➢ Reduced well integrity: Open hole can handle it; casing cannot.

3.7.1 Full Well Integrity

The production casing is always the last casing installed in a well before it is handed to production for installment of the tubing, and therefore needs full well integrity. (Aadnøy, 2010) Should a leak occur in the tubing above the production packer the production casing needs to be designed to handle the load that will be applied to it. It is assumed that the situation will be a gas-filled casing. If both the casing and the open-hole below can handle the gas-filled well scenario, it can be considered to have full well integrity. (Aadnøy, 2010). Design conditions to be established for a full integrity case:

- ➢ Minimum fracture gradient that would be required to reach the end of the next open hole while ensuring full well integrity.

3.7.2 Reduced Well integrity

Because the production casing is the last casing installed and covers the well from the open hole to the wellhead it will act as the first line of defense regarding the casings. The former casings will at this point be installed behind the production casing. Because of this, these casings may be designed for reduced well integrity. Casing is usually weakest below the wellhead and a burst in this area would be disastrous both to equipment and personnel. Because of this we would want the open hole below the casing shoe to be the weakest point. A blowout in this area will not have such an impact on the surface (Aadnøy, 2010). Design conditions to be established for the reduced integrity case:

➢ Minimum fracture gradient what would be required to reach casing setting depth of next casing.
➢ Maximum allowable fracture gradient for the weak point to stay below the shoe.
➢ Maximum size of kick that can be taken and not fracture the formation below the shoe.

This means that that as long as we stay below the maximum kick size, we can ensure full well integrity.

3.8 Major Loads

To evaluate a given casing design it is necessary to analyze a set of loads. These loads on the casing comes from various operations such as running into hole, cementing, later drilling operations, production, intervention, and workovers. In principle, casing loads are mechanical loads, thermal loads, and pressure loads. (Robert F Mitchell, 2007)

- Pressure loads originate from fluids on the inside and outside of the casing, formation pressure influence during drilling and production, as well as pressures on the surface from workover and drilling operations.
- Mechanical loads are more directly associated with movements of the casings. These loads can come from the hanging weight of the casing itself or from shock loads during running in hole, loads generated from packers involved in production and workovers, as well as loads from the casing hangers.
- Temperature loads are produced from changes in temperature which generates in thermal expansion. These loads are induced by drilling, workover and production. IN uncemented intervals these loads may result in bending stress or buckling.
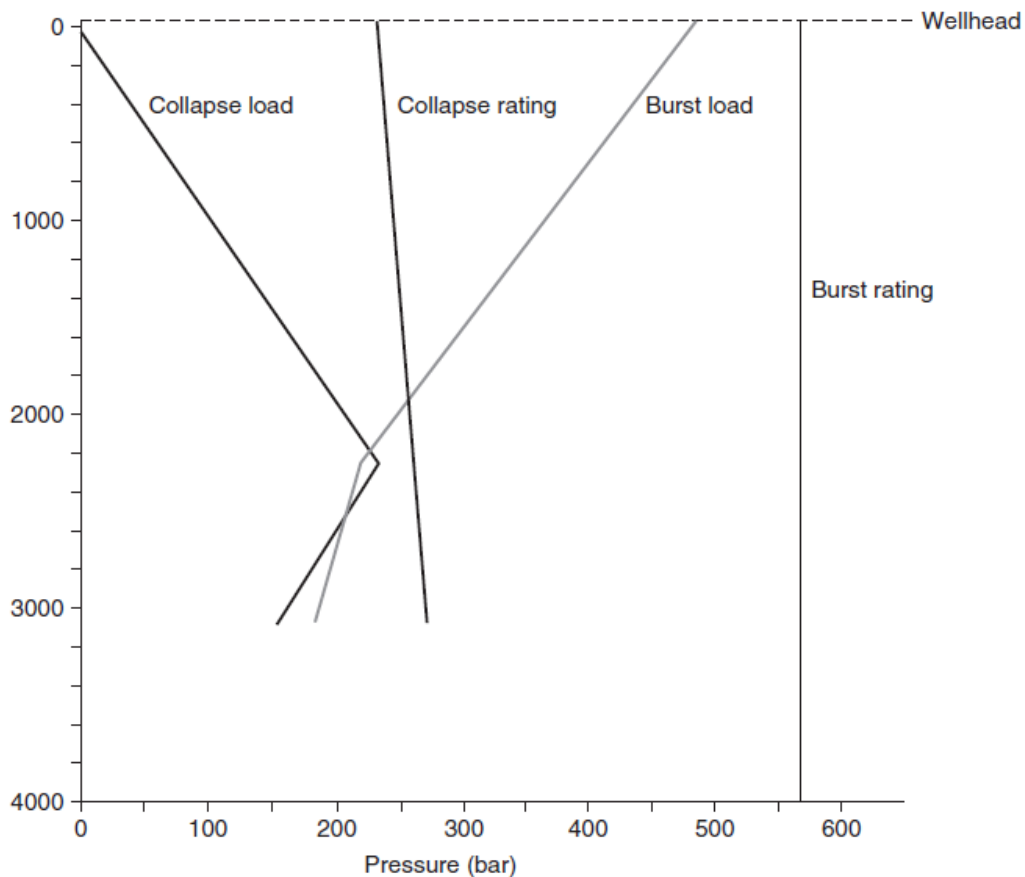
Figure 5: Burst and collapse design of a 14in casing (Aadnøy, 2010)

The figure above shows collapse and burst loads vs depth from the wellhead, as well as burst and collapse rating of a casing. Here it can be observed that the rating of the casing is higher than the load for both mechanisms, so this is within limits. This does not necessarily mean the well has full integrity because these strength ratings can be required to be derated because of other loads, like axial load. More on the specifics of the most important loads experienced on the casings will be explained in detail in the following sections.

3.8.1 Burst

When a casing is subjected to a higher external pressure than internal pressure, and when this difference is greater than the mechanical strength of the casing, it may burst.

$$P_{casing\ strenth}\ <\ [P_{burst} = P_{internal} - P_{external}]$$

 A burst failure is tensile, and it will rupture the pipe axially as shown in the figure below

a) Thin-walled pressure vessel

b) The tangential stress   c) The axial stress
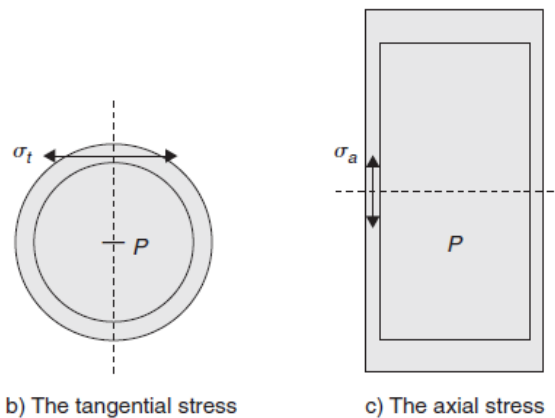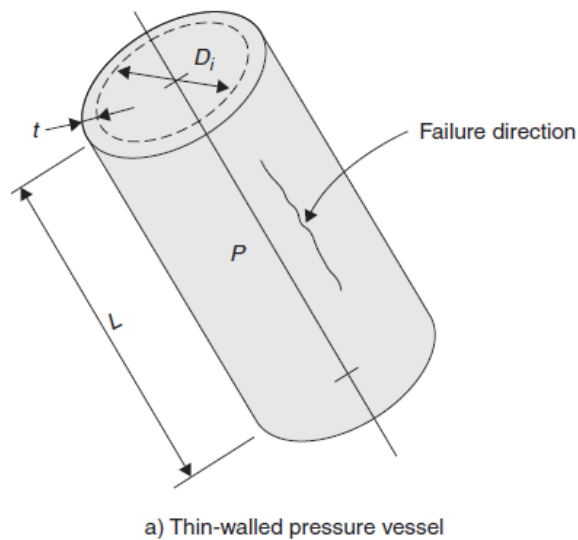
Figure 6: Stresses and failure of thin-walled vessel (Aadnøy, 2010)

Scenarios that can lead to this failure are many, but the mechanics are much the same, Pi > Po, so the design focus is on the conservative criterions: kick during drilling or during production, leaking tubing and a determination of the max kick size a well can take. Should a kick arise during drilling the burst pressure will be highest at the top, but should it be a leaking tubing it will be highest at the shoe.

As seen on figure 6, as well as being mentioned above, the pipe will burst in an axial direction and the reason for this is based in the mechanics and can be explained with some formulas. To explain this in detail, a casing can be considered a thin-walled cylinder and the figure below shows this cylinder with each of the ends closed. The stresses that works on the casing are axially and tangential.

$$\sigma_t = \frac{F_t}{A_t} = \frac{1}{2} P \frac{D_i}{t}$$

$$\sigma_a = \frac{F_a}{A_a} = \frac{1}{4} P \frac{D_i}{t}$$

Combining the two equations results in a ration between the axial and tangential stresses working:

$$\sigma_a = 2\sigma_t$$

From this equation it is observed that the tangential stress acting on the casing is twice that of the axial stress. From experience it is known that if this is the scenario that occurs the cylinder will most likely burst axially. In petroleum terminology this is called bursted casing and it is a tensile failure mechanism. If the tensile material strength is set equal to the tangential stress the following burst equations are acquired:

$$P_{Burst} = 2\sigma_{tensile}\left(\frac{t}{D_i}\right)$$

$$P_{Burst} = 2\sigma_{tensile}\left(\frac{t}{D_o}\right)$$

Using these equations, the burst strength of a casing can be calculated and compared to the burst strength supplied by the manufacturer of the casing. These equations are particularly useful when the casing has been subjected to corrosion or wear because it is depending on diameter and thickness of the walls and can be adjusted accordingly.

3.8.2   Collapse

When the external pressure load exceeds that of the internal pressure, and when this difference in turn exceeds the collapse rating of the casing, collapse is prone to happen.

$$P_{casing\ collapse\ rating} \; < \; \left[P_{collapse} = P_{external} - P_{internal}\right]$$

Collapse loads can originate from Cementing, Mud loss to a thief zone below the packer, loss of injection pressure in a gas filled annulus in a gas lift well, hydrostatic pressure of completion fluid equilibrating with depleted reservoir pressure above a packer, Gas migration in annulus behind production casing where annulus is sealed off and temperature increase in annulus fluids due to production. These are just some of the scenarios that be expected in the lifetime of a well regarding collapse. They are also used as criterions when designing a well, where some are more likely to occur in given wells, and at different times. Different wells with different casing strings, will have different governing criterions and this will be further explained in detail later.

When a casing or tubing collapse, the shape will change from circular into another form. This presents a problem because equipment might have a difficulty passing through an irregular shaped casing. The collapse is a deformation of the casing, and is a geometric failure rather than a materials failure. (Aadnøy, 2010). When a critical pressure is reached, there don't need to be much of a geometrical imperfection or uneven applied load in the casing for it to collapse. Because of this, collapse can be regarded a stability problem. As with the burst equation, the collapse equation is related to the ratio between the thickness of the casing

wall and the diameter of the pipe, and for objects for large diameter and thickness ratio the following equation is valid: (API-5C3, 2018)

$$P_{casing\ collapse\ rating} = \frac{2CE}{1 - v^2} \left\{ \frac{1}{\left(\frac{D_o}{t} - 1\right)^2 \frac{D_o}{t}} \right\}$$

This equation is based for elastic collapse. But there are other collapse mechanisms, such as yield-, plastic-, and transitional collapse. And based on the D/t ratio there are more formulas to choose from, which can be found in the 5C3 API technical report.

3.8.3 Tensile

Tensile load is the load that the casing inflicts onto itself. It comes from the self-weight of the casing and results in a tension failure when the load exceeds the strength of the casing. The result of this failure can in the worst case be a completely parted casing which will lead to time and cost consuming operations to fix. Tensile forces are greatest on the top of the casing string and will decrease towards the bottom. Buoyancy because of well fluids will reduce tensional forces. Pressure differences inside and outside the casing will also affect the tension should both ends be fixed, in that the casing will be elongated or compressed.
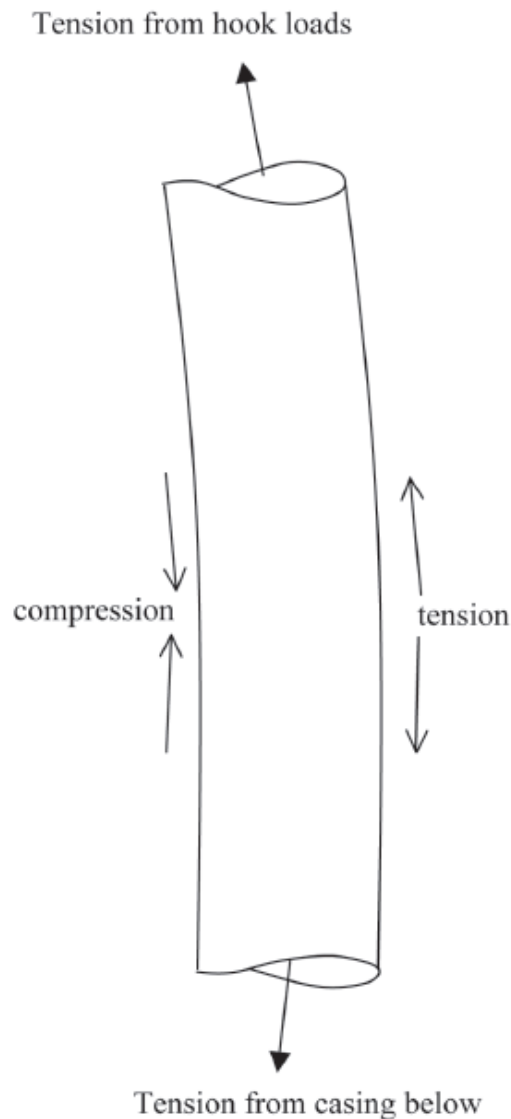
Figure 7: Loads on a casing string during running and on casing landed in a curved section of the borehole (Azar, 2007)

Tensile loads are especially important during installation because the casing will be subject to shocks from narrow points or dog legs while being lowered into the well. Other scenarios that can impose tension loads on the casings are:

- ➢ Freeing of a differentially stuck pipe
- ➢ Pressure testing
- ➢ Static self-weight
- ➢ Bending
- ➢ Drag forces.

Evaluation of maximum tension load criteria will be further explained later in the thesis.

3.8.4 Biaxial

In the previous sections several stresses have been identified or mentioned, such as axial, radial and tangential loads (also called hoop load), these stresses are called principle

stresses. In a realistic environment all these stresses affect the casing string at the same time, and they are interconnected in the way that one load will affect another load on a material, this is what's called biaxial or triaxial loading. An example of the connection between collapse and tension is shown in figure 8 below.
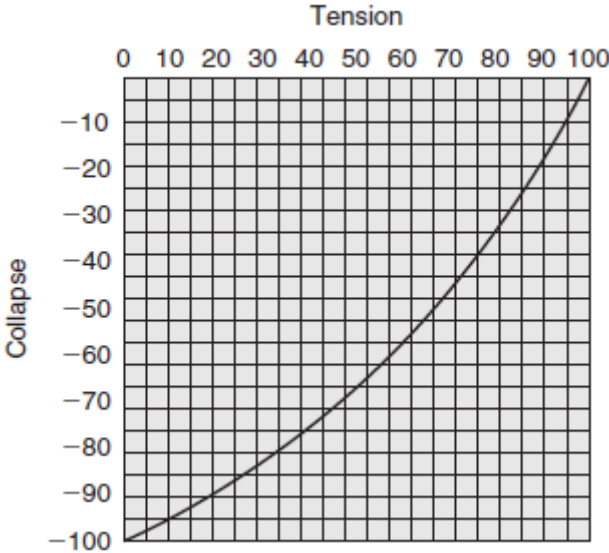
Figure 8: connection between collapse and tension (Aadnøy, 2010)

The words are self-explanatory in that biaxial means that two stresses are working, and one axis is considered zero, and triaxial means that all three axes of stress are being considered (Davis & Bogan, 2014). In addition to these we have the uniaxial situation where we consider one load at a time, which has been explained in the previous burst, collapse and tension sections.

It is well known that materials in general yield before they fail, and the Hencky-von Mises maximum distortion energy theory elaborates on this. It shows that there is a critical yield limit that exists in the casing regardless of the direction:(Aadnøy, 2010)

$$(\sigma_1 - \sigma_2)^2 + (\sigma_1 - \sigma_3)^2 + (\sigma_2 - \sigma_3)^2 = 2\sigma_{yield}^2$$

In this equation, σ_1 , σ_2, and σ_3 refers to the three stresses, axial, tangential and radial and σ_{yield} is the tested yield strength of the casing. This is a triaxial load equation but because of the fact that axial stress governs tensional strength and hoop stress governs burst and collapse (Aadnøy, 2010), the radial stress will be neglected in further calculations because of minor impact. This presents us with a new biaxial form of the Von Mises equation:

$$\sigma_t^2 + 2\sigma_t\sigma_a + \sigma_a^2 = \sigma_{yield}^2$$

Where σ_a and σ_t, is the axial and tangential stresses, respectively. From this formula an elliptic graph can be presented showing the connection between tangential stress, axial stress, and the yield strength of a material. This is shown in figure 9.
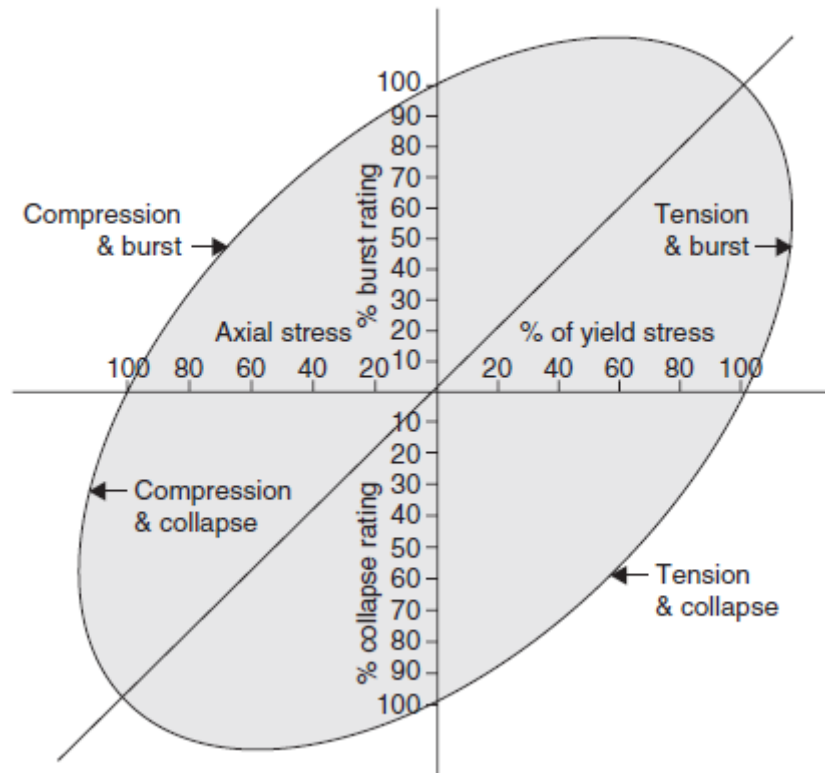
Figure 9: Ellipse of plasticity (Aadnøy, 2010)

The area of particular interest in well design is the bottom right quadrant, showing how collapse strength of a casing is reduced by axial tension.

3.9 Derating of Casing Strength

During the lifecycle of a well the casing will be subjected to additional loads as a result of wear, temperature, corrosion, as well as other effects that can be expected during workovers for instance. These effects can result in failure of the casing.

3.9.1 Temperature effects

Temperature will have a degrading effect on casing and the deeper the casing is set the higher temperature is expected to be present. During circulation this heat will also be transported upwards in the well, exposing the higher parts to an increased temperature as well. In shallow normal-pressure wells, this temperature will usually have a secondary effect on the casing design but there can be cases in deeper wells were loads induced by temperature can be the governing design criteria, such as fluid expansion in a closed of annuli (Robert F Mitchell, 2007). According to Aadnøy (Aadnøy, 2010) no strength corrections is usually applied in wells with temperatures less than 100degC, but for wells with a temperatures higher than this, a strength vs depth curve can be used as seen on the figure below.
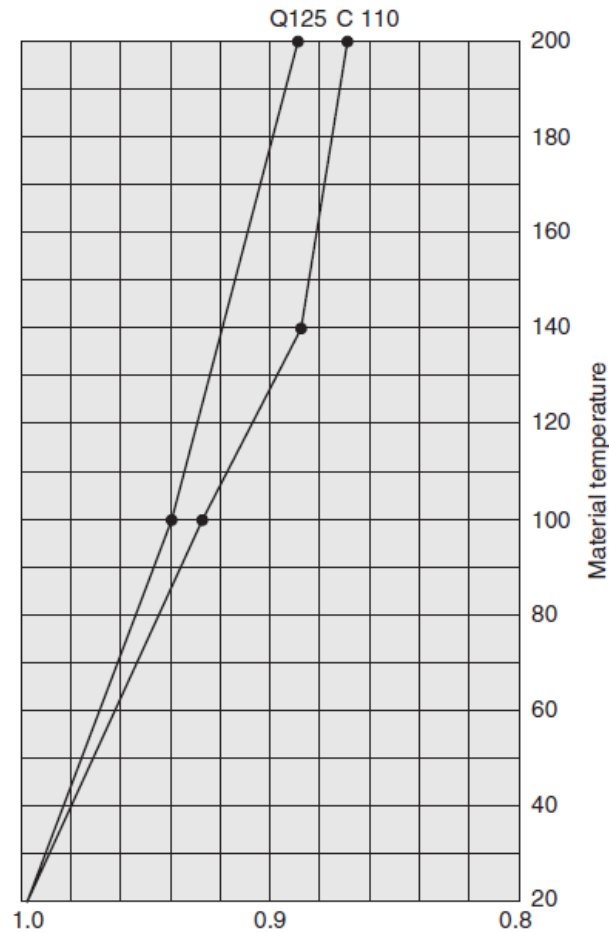
Figure 10: Degrading factor vs temperature for two Casings.(Aadnøy, 2010)

The degrading curve will have to be supplied by the casing manufacturer because there are several different casings, with different strengths, made of different materials, which therefore will be differently affected by temperature.

3.9.2 Corrosion

Corrosion of tubing and casing is a problem because it will alter thickness of the casing which directly affects strength and furthers corrosion effects. The issues surrounding corrosion tend to be complicated, but two aspects that is important, regarding corrosive sour gases, is the effects that lead to the failure of a material in the long time run, and the effects that cause a material to fail in a shorter term, which is embrittlement. Normally when a well is planned and drilled, it is expected to be in production for a certain amount of time and the production casing should be designed to last for the whole period. When the well is completed and a tubing is installed, a production packer is usually inserted just above the reservoir to isolate the annulus between the tubing and production casing. In this annulus there is normally fluid which is not corrosive and therefore results in the casing above the packer not being subjected to a corrosive environment. The part of the production casing below the packer on the other hand is exposed to corrosion in the form of reservoir fluid. This is a known problem and there exist solutions to decrease the corrosive effects on the

casing where such effects are expected, such as producing this part of the casing out of stainless steel. Solutions like this comes at a higher price, but the operation needed to fix the production casing should it fail is very costly

Embrittlement, which is the short-term aspect of corrosion, originates from the presence of sour gases such as H_2S. This is an especially important aspect during drilling. Several factors have to be in place for sulfide stress cracking (SSC) to occur: A susceptible material, tensile stress, H_2S, and water. Are all these in place, cracking mechanisms may initiate in the steel at typical small imperfections or impurities in the bulk or on the surface. (Bruschi, Gentile, & Torselletti, 2017). When a gas like H_2S is dry it normally isn't corrosive, but as soon as water is introduced, the pH of the solution drops, and it is this acid environment that eats the material. Generally softer steel is not susceptible to SSC because of its ductility but higher graded casing might very well be prone to embrittlement. (Aadnøy, 2010).

Because of the effect corrosion has on casing strength a derating of the strength may be warranted when doing calculations for casing that is expected to be in service for many years.

3.9.3   Wear of casing

After each casing section is installed, drilling of the next open hole will commence and that involves drilling through the already installed casing. This induces wear on the casing and results in reduction of casing thickness as well as cracks and cavities on the inside walls, which directly affects the casing resistance to corrosion in a negative way. Casing wear induced by the drill string is an increasing problem for deep wells and/or extended-reach wells because of exposure of casing to the rotation of the drill string (Wu & Zhang, 2005). Casing wear may not be of high importance in all cases, but in HPHT wells it reduces collapse and burst strength more and it is therefore important to predict its impact in wells where this is applicable.(Aadnøy, 2010). Another scenario where casing wear should be given some amount of focus is in casing that are being reused, both in new wells, but also in sidetracking in existing wells.

4 Working Stress Design

4.1 Principle

WSD has been around for a long time and already from early 1900s nearly all reinforced concrete design in USA was performed using the WSD design method. In early 1960s another stress design, called Ultimate-Strength design, gained popularity in the concrete industry and slowly phased out WSD (McCormac & Brown, 2014). In the oil and gas industry, working stress design continues to be the traditional and most used approach to designing oilfield tubulars. Back in 1970 Charles Prentice published a paper called "Maximum Load Casing Design" (Prentice, 1970) where he addressed the need to properly evaluate the different loads imposed on each of the casing strings separately. He explained that since burst is the dictating factor for most of the strings it shall be evaluated first. After that, collapse strength should be evaluated. Based on these calculations the weights, grades and lengths of each sections can be determined, before the tensional loads comes in focus and from that the determination of coupling types. Each of these steps can, if calculation demand it, upgrade the string chosen from the burst calculation. Last step is biaxial evaluation to determine if compressional and tensional loads will have reduced the burst and collapse strength. *"By initially choosing the least expensive weights and grades of casing that will satisfy the burst loading, and upgrading only as called for by the prescribed sequence, the resulting design will be the most inexpensive possible that can fulfill the maximum loading requirements" (Prentice, 1970).*

4.2 Design Factors

WSD uses a deterministic approach to oilfield tubular designs for calculating strength and loads. The load that can be applied to the tubular is restricted by the strength of the tubular combined with design factor. *"Design factor is the minimum allowable safety factor, which is expressed as the ratio between the rated strength of the material over the estimated maximum load" (NORSOK, 2013).* This means that for a load to be considered allowed it must have a safety factor that is either higher than or equal to the design factor. The safety factor can be obtained by dividing the strength of the material by the load applied. This method is not restricted to strength vs load scenarios and can therefore be applied to many kinds of designs, although the name itself derives for stress design applications.

$$\sigma_{load} \leq \frac{1}{DF}\sigma_{strength}$$

$$SF = \frac{\sigma_{strength}}{\sigma_{load}}$$

$$DF = \frac{\sigma_{strength}}{\sigma_{load\ limit}}$$

To present an example, we can use a C95, 36lbs/ft 9-5/8 pipe, which has a reported burst strength of 419 bar (Aadnøy, 2010). By using the Burst design factor of 1.1 presented by NORSOK, we obtain a maximum allowed burst load of $\frac{419\text{bar}}{\text{DF}=1.1}=381\text{bar}$. This means that for a casing string to be approved during the casing design, the calculated expected burst load on the casing cannot exceed this value. Several standards exists throughout the globe containing guidelines on design factors, but It is normal that companies have their own regulations and experience that they base their design factors on, as well as on government requirements (R.F. Mitchell & Miska, 2011).

4.3   Design Criteria

The most critical activity in the well design process is selecting the right design criteria to investigate for the various casing strings. Most likely several criteria will be relevant for a given string and therefore should all be considered. From this, realistic scenarios can be established (Aadnøy, 2010). Burst, collapse and tensile design criteria will be in focus here.

4.3.1   Burst Design Criteria
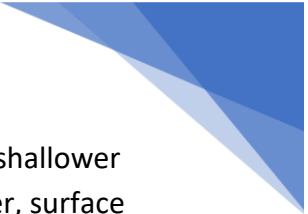
Several situations may arise where the conditions can result in a bursted pipe. Some of these are: (Aadnøy, 2010)

- Pressure of the hydrostatic mud inside a casing exceeds the pressure of the formation or the pressure outside the casing.
- Well shut-in: Because of differential borehole pressure, fluid of the formation can enter into the wellbore.
- A kick induced gas bubble migrating up the casing.
- Circulating a kick
- Migration of gas upwards in the wellbore after temporary abandonment or emergency disconnect.
- Tubing leak just below the wellhead during pressure testing or production
- Expansion of fluids due to temperature in the annulus between casing strings.
- During squeeze cementing.

These situations are all different but from a pressure point of view many of them are similar and can be compressed into three main categories, according to Aadnøy (Aadnøy, 2010).

4.3.1.1   Casing filled with formation fluid or gas

For a producing well the gas filled criterion must be used on the production casing since this is a realistic scenario. It will produce formation fluids and/or gas and it will be pressure tested. For this criterion it is assumed that the well is completely filled with gas or fluids from the formation and then shut in. The inside pressure right below the well head for this scenario is that of the formation minus the weight of the gas or fluid column. Outside pressure is the pressure of whichever fluid or material that is present. This is a very

conservative criterion, and in cases where there are no flow test options on the shallower casing, this criterion becomes too conservative. As explained in an earlier chapter, surface and intermediate casing may have reduced well integrity, and therefore an upper size limit of a kick is introduced instead, giving room for cheaper casing.(Aadnøy, 2010)

4.3.1.2   Maximum gas kick

This criterion is based on the maximum kick size that can be taken at the depth of the next open hole section that the formation can handle without being fractured at the shoe of the casing investigated. This is, as mentioned above, of particular interest for the shallower casing which are not to be production casing and therefore can be allowed reduced well integrity. As for most criteria, the base requirement is to avoid that the weak point in the well is directly below the wellhead, therefore this method utilizes maximum leak-off, which is a value specific to the casing type chosen. (Aadnøy, 2010)

4.3.1.3   Leaking tubing

The tubing in a production well may leak, either during well testing or at a later stage in its lifetime. This leak usually occurs close to the wellhead at the top. The tubing is locked in place down towards the reservoir using production packers which seals of the annulus between the tubing and the production casing or production liner. This annulus is occupied by a completion fluid and should the tubing leak at the top, the inside tubing pressure will be superimposed on top of the annulus pressure (Aadnøy, 2010). This may result in a bursted casing at the most exposed region of the casing which would be at the depth of the packer. This criterion is interconnected with the gas-filled casing criterion.

4.3.1.4   Bullheading

Bullheading is to pump fluids into the formation by establishing an over-pressure from surface. Usually this is conducted as part of a well control event where formation fluids have entered the wellbore. This criterion is evaluated on casings or liners placed over a reservoir interval, and thus perforated, to allow for production from this area. During this bullheading event the said perforations may get plugged which will result in the buildup of pressure alongside the inner wall of the casing or liner and this can cause the pipe to burst. It can be assumed that for this criterion, the bullheading fluid will be the formation fluid that has entered the pipe.

4.3.2   Collapse Design Criteria

As for burst criteria, several situations exist that can lead to collapse of the casing. Some of which are: (Aadnøy, 2010)

- Lost circulation in the well which causes the mud level to drop. This can be caused by formations with very high permeability, natural fractures or high mud weights.
- In cement squeeze jobs through perforations, pressure behind the casing may arise.

- During regular cementing of casing string the pressure behind may arise due to the cement and surpass the inside pressure
- Drilling through salt areas. Salt has plastic properties and may cause pressure on the casing.
- In deep waters, problems due to the casing string not being properly filled with mud can cause collapse.
- Temperature effects in closed annuli.

Following is two much used criteria that covers most of the above points.

4.3.2.1   Mud losses to a thief zone

During drilling there is a possibility to come into highly permeable zones, these zones can come completely unexpectedly and in the worst cases drain the well fluids from the well. The result from such an occurrence is a pressure decrease in the wellbore while the pressure behind the casing stays unaffected. This gives way to a potential collapse should the differential pressure surpass the collapse rating of the casing. Several criteria exist covering mud loss scenarios in various points in time in the lifecycle of a casing, and the most realistic scenario should be designed to each specific well with associated well properties (Aadnøy, 2010).

4.3.2.2   Collapse during cementing

The casing strings can be cemented in place either partially or fully. This criterion is usually of most significance in casing where the cement job reaches all the way to the seabed, which is regular for the surface casing and conductor. Immediately after the cementing operation a slurry column comprised of different lead and tail densities makes up the external pressure of the casing, with the addition of the sea water column down to the seabed. The inside pressure is that of the displacing fluid such as mud. If the mud is lightweight the collapse load will be increased. For this criterion the maximum load induced is likely to occur at the casing shoe. (Aadnøy, 2010)

4.3.2.3   Collapse due to plugged perforations

If the perforations in the producing area gets plugged during production, it will result in an outside pressure of the liner equal to that of the formation pressure and an inside pressure corresponding to the density of the formation fluid. This criterion is only applied in the reservoir interval and it is accounted for corrosion on the liner below the packer over time.(Aadnøy, 2010)

4.3.3   Tensile Design Criteria

When a casing is installed, and at lager stages, it will experience several mechanical loads which is evaluated as part of the casing design. Some of these axial loads occur from, amongst other, running in hole, overpull while running, Shock loads, Service loads and bending loads. Some of the historically most used tension criterion is the Air weight of the

casing alone and that of the buoyed weight with added overpull. (Robert F Mitchell, 2007). Typical tension forces usually considered in casing design is according to Aadnøy the following: (Aadnøy, 2010)

- Weight of casing in air minus buoyancy, plus drag and bending forces as well as pressure test loads.
- Weight of casing in air minus buoyancy, plus drag and bending forces, as well as shock loads.

Which criterion to use is dependent on when the maximum tensile load is expected. Should it be during installation the above loads should be sufficient, but if the maximum load is expected later in the casing's lifecycle, casing wear as explained earlier will play a part in the calculation.

5 Optimization Program

5.1 Preliminary introduction

Based on the introductory theory and on the well design examples presented in chapter 5 and 6 of Modern Well Design (Aadnøy, 2010), an Excel based program has been made. The program aims to optimize the casing design progress by making it as automatic as possible based on a set of design criteria chosen in MWD, thus reducing the amount of input variables needed. By only utilizing standard excel functions the program did not achieve the complexity desired, so the VBA programming extension for excel has been used in certain aspects of the program. Because of the desire to make the program as dynamic as possible, where every calculation and graphical result is altered with every minor change in the input variables, some macros have been designed using VBA programming. This is especially important regarding the graphic results, where for instance, updating axis limits in graphs automatically is an option that is lacking in basic excel. Also included is buttons connected to macros for quickly switching between relevant sheets in the program.

The program was initially designed to match the string setup that is presented in chapter 5 of Modern Well Design; Surface casing, intermediate casing, production liner, reservoir liner, but with later use of several other wells, with completely different setups, the need for modifications quickly arose. The latest version includes other well setups, with strings such as intermediate liner and production liner.

 Various additional setup options have been included in the program, such as perforating the lower parts of the production casing/liner, production packers in different casing strings, automatic or manual insertion of gradients and more.

The program as it is now can be used for different applications, some of which are:

- <u>Evaluation</u>: It can be used to evaluate an already designed or constructed well where degrading strength effects can be adjusted accordingly based on lifetime.
- <u>Full design</u>: It can be used to design the complete casing program from scratch based on given values of geological data such as pore pressure gradient, fracture gradient and zones of interest. Based on these parameters, setting depth, mud weights, cement density, string setup and types of casing, can be determined.
- <u>Partial design</u>: It can be used to adjust a partially designed well where for instance the setting depths, strings, mud weights and cement densities have been determined. Based on this preliminary design the types and grades of casing can be chosen to be able to withstand the calculated pressures and loads that will occur based on the data that is already incorporated as a foundation.
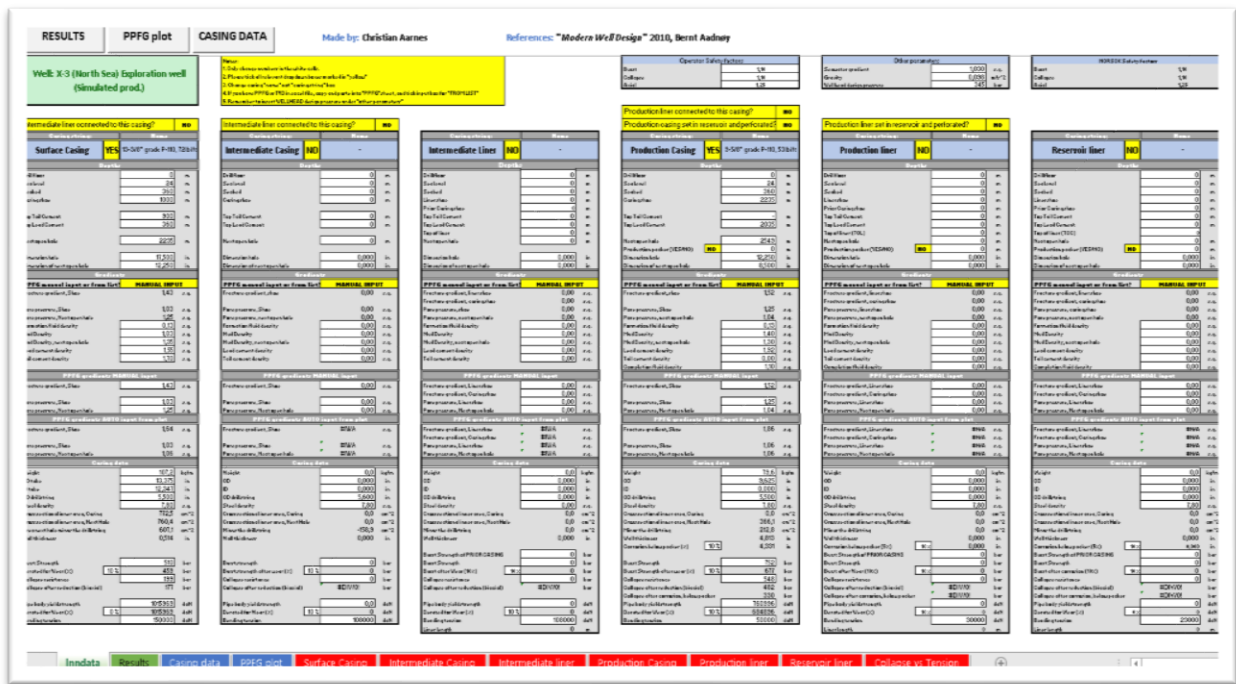
Figure 11: Front page of the program where data is inserted

The green area in the top left corner is an optional input area for the well name which can be used for better transparency and to keep your wells organized. Yellow area lists a set of "rules" and "reminders" applied to the document explaining which cells should be modified and which cells should not. Also located in this area is 3 navigational buttons which directs the user to the relevant sheets in the document. Lastly it includes author name and main reference for the program.

The three boxes located top right includes standard parameters that is constant for all the calculations specific to a well. This includes operator safety factors, seawater gradient, gravitational gradient, and wellhead design pressure. NORSOK safety factors has been included for comparison.

5.2   How it works

To explain the inner workings of the program, the intermediate casing will be presented as an example from start to end. The example illustration will be that of an evaluation of a completed well. Some of the background calculations will be too complex to be introduced in detail so they will be explained in a more understandable way. Some of the excel functions used for these calculations will be generally presented in the next section instead.

5.2.1   Collecting dataset:

Input data will originate from different sources depending on which of the aforementioned applications it will be used for. If it is from scratch it is likely to be based on a pressure evaluation plot from geological logging. If it is a fully or partially designed well the data are likely to be obtained from a drilling program or from a well program. The data for this

example is obtained from Modern Well Design (Aadnøy, 2010) with some modifications to make feasible for a dynamic program.

5.2.2 Implementing dataset

In the inndata page there are separate sections for each casing strings and liners. In figure 12 below the intermediate casing is presented.

Intermediate liner connected to this casing?			NO	
Casing string:		**Name**		
Intermediate Casing	**YES**	13-3/8" grade X-70, 72 lbs/ft		
Depths				
Drillfloor		0	m	
Sea level		25	m	
Seabed		225	m	
Casing shoe		1820	m	
Top Lead Cement		1685	m	
Next open hole		2365	m	
Dimension hole		16,000	in	
Dimension of next open hole		12,250	in	
Gradients				
PPFG manual input or from list?		MANUAL INPUT		
Fracture gradient, shoe		1,70	s.g.	
Pore pressure, Shoe		1,40	s.g.	
Pore pressure, next open hole		1,55	s.g.	
Formation fluid density		0,76	s.g.	
Mud Density		1,50	s.g.	
Mud Density, next open hole		1,70	s.g.	
Lead cement density		1,45	s.g.	
Tail cement density		0,00	s.g.	

PPFG gradients MANUAL input			
Fracture gradient, Shoe		1,70	s.g.
Pore pressure, Shoe		1,40	s.g.
Pore pressure, Next open hole		1,55	s.g.
PPFG gradients AUTO input from plot			
Fracture gradient, Shoe		1,85	s.g.
Pore pressure, Shoe		1,39	s.g.
Pore pressure, Next open hole		1,06	s.g.
Casing data			
Weight		107,1	kg/m
OD		13,375	in
ID		12,360	in
OD drillstring		5,600	in
Steel density		7,80	s.g.
Cross sectional inner area, Casing		774,1	cm^2
Cross sectional inner area, Next Hole		760,4	cm^2
Minus the drillstring		601,5	cm^2
Wall thickness		0,508	in
Burst strength		510	bar
Burst strength after wear (%)	10 %	459	bar
Collapse resistance		199	bar
Collapse after reduction (biaxial)		174	bar
Pipe body yield strength		1016000,0	daN
Derated for Wear (%)	10 %	914400	daN
Bending tension		108000	daN

Figure 12: Example data for an intermediate casing.

All the white colored cells above are for the manual input of data. All the relevant depths for the casing investigated, all the gradients for the casing interval and the next open hole, and all the relevant strengths and dimensions connected with the specific casing selected.

The yellow areas are all "drop-down" menus and the answer selected directly affects the background calculations conducted. If the box for "Intermediate liner connected to this casing" is ticked "YES" the calculations on this casing will be based on parameters from the next open hole after the liner, instead of just the next open hole from this casing. In a formation filled casing scenario for instance, this can lead to a higher shut in pressure below the wellhead than it would if no liner was present if the depth of the open hole following the liner is deeper. The "PPFG manual input or from list?" menu is ticked off to tell the program if the pore pressure gradient and frac gradient should be collected from the manual input section or automatically search for the corresponding values to the specific depths in the PPFG plot. The casing data input section is fairly straightforward input of values from the casing table, except from the derating. Several derated values can be observed here. The

burst and yield strength reduction after Wear is based on the percentage that is inserted and this is adjusted according to the user's preferences and utilized in the calculations wherever they are relevant. The biaxial reduction of collapse strength is based on a background calculation that will be explained in the next sections.

5.2.3   Utilizing the PPFG Plot

The "Pore Pressure and Fracture Gradient Plot" page in the program, is where the columns of fracture pressure and pore pressure vs TVD obtained from logging can be inserted.
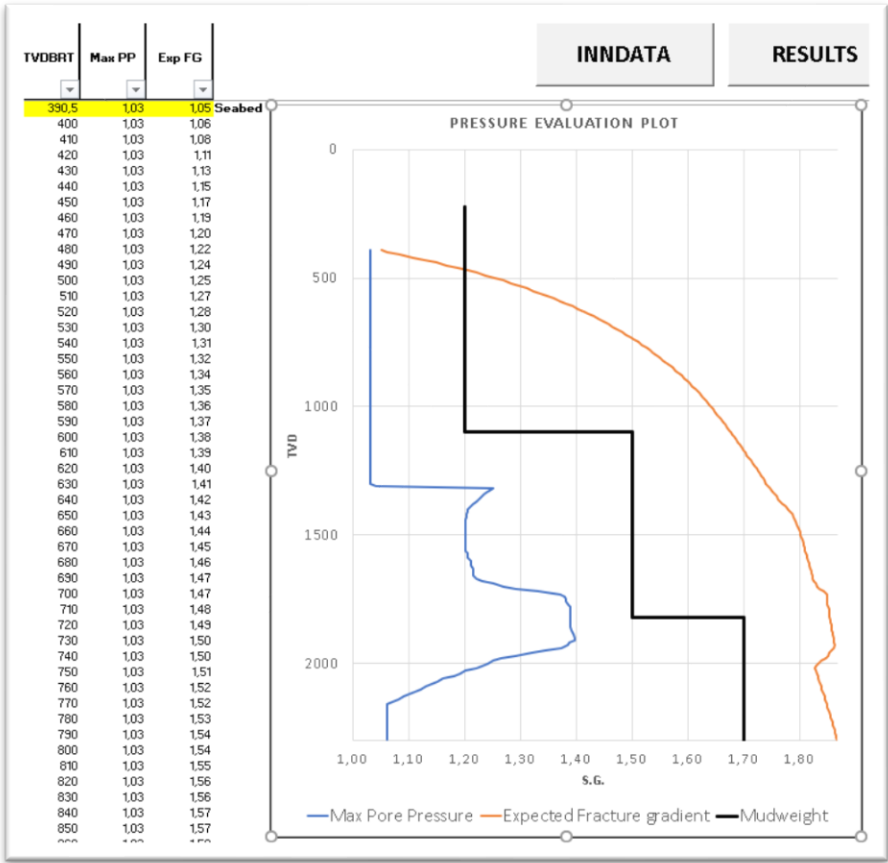
Figure 13: PPFG example Plot

If this data is provided to the user in columns the program is designed so that it can be copied and pasted into columns A, B and C, and automatically update the Plot according to these values. It is programmed in such a way that the plot will choose values from these columns regardless of how far down the numbers go. This dataset is also where the "Auto input from Plot" is collecting its data. This is a "lookup" function that will be explained in section 5.3. The mud weight graph is automatically updated according to input values for setting depth and mud weights for each section.

Note that this plot is based on the inserted values in the columns so if the user does not possess the necessary values, the plot will not be relevant and the porepressure and fracture gradients must be inserted manually under "inndata".

5.2.4 Casing background calculations

Based on the all the inserted data by the user in "inndata", a number of background calculations are conducted in separate sheets for each casing. The intermediate casing will continue to be the example casing.

Intermediate Casing	13-3/8" grade X-70, 72 lbs/ft		
Criteria evaluated	BURST: Formation fluid filled casing		
	COLLAPSE: Well fluid loss due to a thief zone		
Overview			
Strength/load ratio	Axial/Tension	2,40	Good
	Burst	2,59	Good
	Collapse	2,02	Good
Full/reduced well integrity?	Reduced		
Weak point in the well	Shoe		
BURST CALCULATIONS			
Post-installation: Formation fluid filled casing			
Assumptions	Seawater behind casing		
External Pressure	Wellhead	23	bar
	Shoe	184	bar
Internal Pressure	Bottom of open hole	359	bar
	Shoe	319	bar
	Wellhead	200	bar
Burst load	Wellhead	177	bar
	Shoe	135	bar
Post-Installation: formation fluid filled casing (from intermediate LINER)			
External Pressure	Wellhead	23	bar
	Top of liner	101	bar
Internal Pressure	Bottom of open hole	359	bar
	Wellhead	200	bar
	Top of liner	258	bar
Burst load	Wellhead	177	bar
Maximum Burst load	Highest value	177	bar

Figure 14: Intermediate Casing calculation example 1/3

Figure 14 above shows the top of the calculation sheet for the intermediate casing. It starts of by presenting the results from the calculations. The numbers presented under "Overview" on Axial, burst and collapse factors are calculated from the inserted casing strengths under inndata compared to calculations conducted on this sheet. The "good/bad" cell is designed to output "good" if the values are in accordance with operator SF, or "bad" if the calculated design factor is below the SF.

Next is the burst calculations, where the formulas mostly are in accordance with chapter 5 calculations in Modern Well Design (Aadnøy, 2010) but with some modifications to better fit a dynamic program such as this. Orange cells lists assumptions made specific to this criterion

for this specific casing. Green cell explains which criterion that is investigated and in which part of the casing's lifecycle the calculations are done. The brownish cell introduces the same calculations if the casing should have a liner connected to it. This option is ticked off as "yes/no" under inndata for the intermediate casing. Maximum burst load returns the highest burst load value for use in further calculations based on a set of IF functions that is based inndata input.

COLLAPSE CALCULATIONS			
Installation: Well fluid loss to a thief zone			
Assumptions:	Thief zone at the bottom of the well		
	Outside fluid is mud		
	Inside mud level stabilizes at Hydrostatic seawater pressure		
	Air inside casing above Mudlevel		
Height of mud level	Height from drillfloor	587	m
External Pressure	At shoe	268	bar
	Wellhead	33	bar
	at calculated height	86	bar
Internal Pressure	At shoe	181	bar
Collapse Load	At shoe	86	bar
Post-installation: Well fluid loss to a thief zone. (from intermediate LINER)			
Is the calculated depth in casing interval?	YES	587	m
External Pressure	Wellhead/seabed	33	bar
	At calculated height	86	bar
	Top of liner	147	bar
Internal Pressure	Wellhead/seabed	0	bar
	At calculated height	0	bar
	Top of liner	61	bar
Collapse load	At calculated height	86	bar
Maximum Collapse load	Highest value case	86	bar

DERATING OF COLLAPSE RESISTANCE DUE TO BI-AXIAL FORCES	
Axial load/strength ratio	0,24
Strength reduction factor from fig.	0,88
Derated collapse pressure	174

Figure 15: Intermediate casing calculations example 2/3

The collapse calculations presented in figure 15 above is mostly based on the same set of rules as the burst calculations that already has been explained, but with some differences, which are mostly several interconnected IF rules, concerning the mud height in the event of a loss zone in the bottom of the well should the casing have a liner connected to it. The aim is that different rules and calculations will be applied based on if the mud level is in the casing interval or in the next liner interval.

The next calculation is for the derating of collapse resistance from biaxial forces. These values are based on tensional calculations further below compared to the axial strength of the casing. This returns a relationship of 0,24 in this case, which through a lookup function collects data from a "tension vs collapse" and here returns the value 0,88. This is the derating factor that is used on the collapse resistance of the casing. In this example the new

resistance is 174 down from 199 (Shown in figure 12.) This plot will be explained in the next section.

TENSIONAL LOAD CALCULATIONS			
Assumptions	Key criterion: Weight of casing in mud + bending + testing		
	Casing landing in mud		
	Max loads occur during isntallation		
Weight	String	167408	daN
	Buoyed string	135214	daN
Casing test pressure	Bumping plug and set cement	177	bar
Tension from testing	Closed chamber	137127	daN
Bi-axial collapse correction	Buoyed weight + Bending	243214	daN
Design tensional load	Mud + Bending + Testing	380341	daN

WELL INTEGRITY EVALUATION			
Pressure	at shoe	319	bar
Pressure gradient	at shoe	1,79	s.g.
Full/reduced well integrity?	Reduced		
Kick Margin			
Assumptions	Kick from the bottom of the well		
Maximum height of formation influx		377	m
Volume of influx		22,7	m^3
Weak point in the well			
Assumptions	Based on design factors in inndata. Change accordingly		
	Well is filled with formation fluid and shut in		
Maximum allowable burst pressure	Wellhead	464	bar
Corresponding Pressure	at shoe	582	bar
Pressure gradient	at shoe	3,27	s.g.

Figure 16:Intermediate casing calculation example 3/3.

Figure 16 shows the rest of the calculations conducted for the intermediate casing string. Here it's also mostly straight forward calculations based on theory presented earlier in the thesis, with several interconnected IF functions implemented to alter/decide which calculations are done and which results are shown.

5.2.5   Biaxial reduction of collapse resistance.

In earlier theory it has been explained how tensional forces affect the collapse resistance and this had to be implemented somehow into the program in a way that make it automatic.
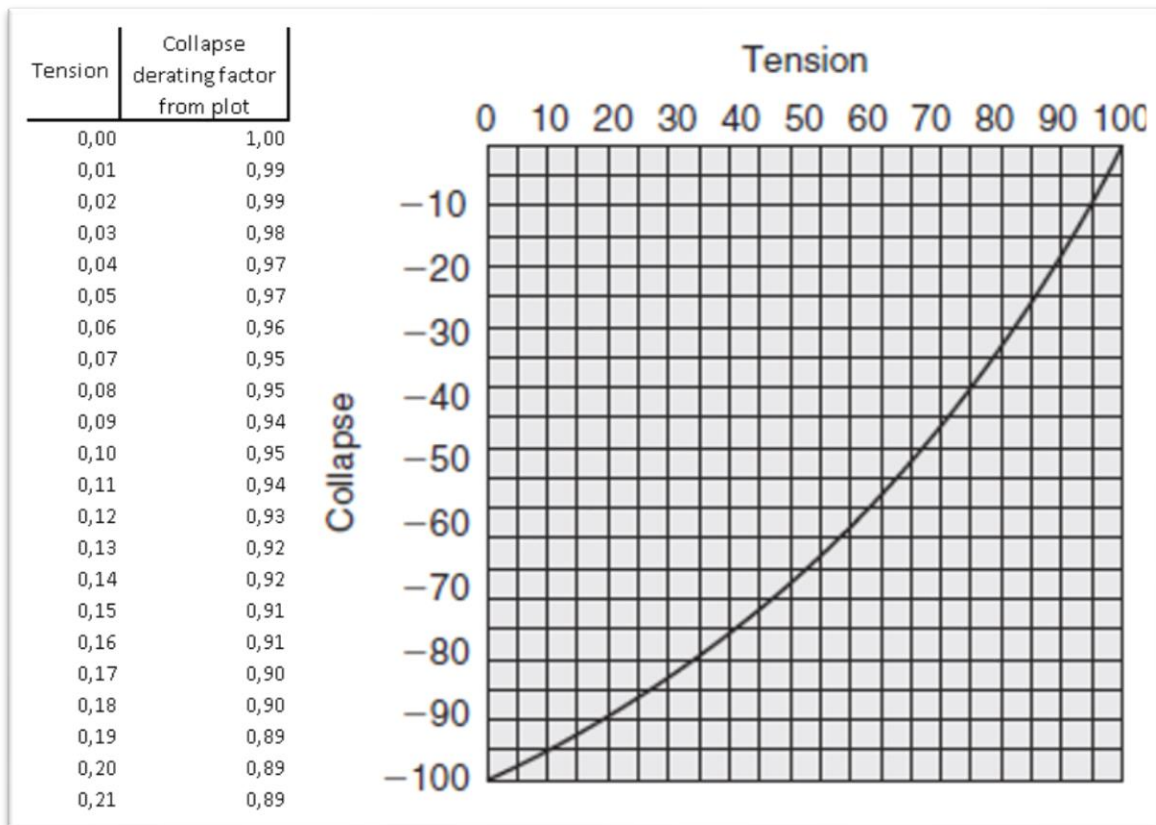
Tension	Collapse derating factor from plot
0,00	1,00
0,01	0,99
0,02	0,99
0,03	0,98
0,04	0,97
0,05	0,97
0,06	0,96
0,07	0,95
0,08	0,95
0,09	0,94
0,10	0,95
0,11	0,94
0,12	0,93
0,13	0,92
0,14	0,92
0,15	0,91
0,16	0,91
0,17	0,90
0,18	0,90
0,19	0,89
0,20	0,89
0,21	0,89

Figure 17: Biaxial reduction of collapse resistance plot

In figure 17 the values for the biaxial reduction of collapse resistance is shown. The plot is obtained from Aadnøy (Aadnøy, 2010) and the numbers located in columns on the left side is manually read from the plot. This was the only way to make the process of collapse reduction automatic. An excel "Vlookup" function is utilized.

5.2.6   Casing data table

The casing data table provided in the program is not connected to any functions but is merely there to assist the user in effectively finding suitable casing for the application investigated.

O.D. (inch)	Nominal Weight (lb/ft)	Nominal Weight (kg/m)	Grade	Collapse resistance (psi)	Collapse resistance (bar)	Burst strength (psi)	Burst Strength (bar)	Pipe body yield strength (daN)	Wall Thickness (inch)	I.D. (inch)	Cross-sectional area (cm^2)	Drift diameter (inch)	Index
4,5	9,5	14,1	J-55	3310	228	4380	302	53761	0,205	4,090	18	3,965	4,5" grade J-55, 9,5lb/ft
4,5	9,5	14,1	K-55	3310	228	4380	302	53761	0,205	4,090	18	3,965	4,5" grade K-55, 9,5lb/ft
4,5	9,5	14,1	LS-65	3600	248	5180	357	63580	0,205	4,090	18	3,965	4,5" grade LS-65, 9,5lb/ft
4,5	10,5	15,6	J-55	4010	276	4790	330	57989	0,224	4,052	19	3,927	4,5" grade J-55, 10,5lb/ft
4,5	10,5	15,6	K-55	4010	276	4790	330	57989	0,224	4,052	19	3,927	4,5" grade K-55, 10,5lb/ft
4,5	10,5	15,6	LS-65	4420	305	5660	390	75035	0,224	4,000	22	3,927	4,5" grade LS-65, 10,5lb/ft
4,5	11,6	17,3	J-55	4960	342	5350	369	63549	0,250	4,000	22	3,875	4,5" grade J-55, 11,6lb/ft
4,5	11,6	17,3	K-55	4960	342	5350	369	63549	0,250	4,000	22	3,875	4,5" grade K-55, 11,6lb/ft
4,5	11,6	17,3	LS-65	5560	383	6320	436	75035	0,250	4,000	22	3,875	4,5" grade LS-65, 11,6lb/ft
4,5	11,6	17,3	L-80	6350	438	7780	536	92413	0,250	4,000	22	3,875	4,5" grade L-80, 11,6lb/ft
4,5	11,6	17,3	HCL-80	8650	596	7780	536	92413	0,250	4,000	22	3,875	4,5" grade HCL-80, 11,6lb/ft
4,5	11,6	17,3	N-80	6350	438	7780	536	92413	0,250	4,000	22	3,875	4,5" grade N-80, 11,6lb/ft
4,5	11,6	17,3	HCN-80	8650	596	7780	536	92413	0,250	4,000	22	3,875	4,5" grade HCN-80, 11,6lb/ft
4,5	11,6	17,3	C-90	6810	470	8750	603	103935	0,250	4,000	22	3,875	4,5" grade C-90, 11,6lb/ft
4,5	11,6	17,3	S-95	8650	596	9240	637	109756	0,250	4,000	22	3,875	4,5" grade S-95, 11,6lb/ft
4,5	11,6	17,3	T-95	7030	485	9240	637	109756	0,250	4,000	22	3,875	4,5" grade T-95, 11,6lb/ft
4,5	11,6	17,3	C-95	7030	485	9240	637	109756	0,250	4,000	22	3,875	4,5" grade C-95, 11,6lb/ft
4,5	11,6	17,3	HCP-110	8650	596	10690	737	126979	0,250	4,000	22	3,875	4,5" grade HCP-110, 11,6lb/ft
4,5	11,6	17,3	P-110	7580	523	10690	737	126979	0,250	4,000	22	3,875	4,5" grade P-110, 11,6lb/ft
4,5	13,5	20,1	LS-65	7300	503	7330	505	84524	0,290	3,920	25	3,795	4,5" grade LS-65, 13,5lb/ft
4,5	13,5	20,1	L-80	8540	589	9020	622	104011	0,290	3,920	25	3,795	4,5" grade L-80, 13,5lb/ft
4,5	13,5	20,1	HCL-80	10380	716	9020	622	104011	0,290	3,920	25	3,795	4,5" grade HCL-80, 13,5lb/ft
4,5	13,5	20,1	N-80	8540	589	9020	622	104011	0,290	3,920	25	3,795	4,5" grade N-80, 13,5lb/ft
4,5	13,5	20,1	HCN-80	10380	716	9020	622	104011	0,290	3,920	25	3,795	4,5" grade HCN-80, 13,5lb/ft
4,5	13,5	20,1	C-90	9300	641	10150	700	117042	0,290	3,920	25	3,795	4,5" grade C-90, 13,5lb/ft
4,5	13,5	20,1	S-95	10380	716	10710	738	123499	0,290	3,920	25	3,795	4,5" grade S-95, 13,5lb/ft
4,5	13,5	20,1	T-95	9660	666	10710	738	123499	0,290	3,920	25	3,795	4,5" grade T-95, 13,5lb/ft
4,5	13,5	20,1	C-95	9660	666	10710	738	123499	0,290	3,920	25	3,795	4,5" grade C-95, 13,5lb/ft
4,5	13,5	20,1	P-110	10680	736	12410	856	143102	0,290	3,920	25	3,795	4,5" grade P-110, 13,5lb/ft
4,5	15,1	22,5	L-80	11090	765	10480	723	116632	0,337	3,826	28	3,701	4,5" grade L-80, 15,1lb/ft
4,5	15,1	22,5	HCL-80	12330	850	10480	723	116632	0,337	3,826	28	3,701	4,5" grade HCL-80, 15,1lb/ft
4,5	15,1	22,5	S-95	12330	850	12450	858	138557	0,337	3,826	28	3,701	4,5" grade S-95, 15,1lb/ft
4,5	15,1	22,5	P-110	14350	989	14420	994	160481	0,337	3,826	28	3,701	4,5" grade P-110, 15,1lb/ft
4,5	15,1	22,5	Q-125	15840	1092	16380	1129	182294	0,337	3,826	28	3,701	4,5" grade Q-125, 15,1lb/ft

Figure 18: Casing data table

The table consists of about 1800 casings and tubing with parameters given in both metric and imperial units. Basic casing data has been collected from a bachelor thesis (Hagen, 2016) and then modified with additional calculations and data to suit this program. Indexing to sort the list based on preferences has been introduced for the user's convenience. This function can be utilized by using the dropdown button on the top row.

5.2.7   Presenting relevant results

The last stage of the program is to collect all the relevant results obtained during the whole process and present them in a clear way that is understandable and satisfactory to the user.

Field: Well: Example well		Casing specific results								
Casing type	Casing grade	Burst – OK?		Collapse – OK?		Tension – OK?		Well Integrity	Weak Point	Max Kick Size [m]	Max Frac. grad
Surface Casing	18-5/8" grade X-70, 84.5lb/ft	1,64	YES	1,13	YES	1,61	YES	Reduced	Shoe	40,0	2,27
Intermediate Casing	13-3/8" grade X-70, 72 lbs/ft	2,59	YES	2,02	YES	2,40	YES	Reduced	Shoe	22,7	3,27
Intermediate Liner	13-3/8" grade X-70, 72 lbs/ft	2,59	YES	2,08	YES	3,06	YES	Reduced	Shoe	30,9	3,27
Production Casing	9-5/8" grade L-80, 47lbs/ft	2,29	YES	1,60	YES	1,46	YES	full	Wellhead	22,1	0,24
Production liner	9-5/8" grade L-80, 47lbs/ft	2,24	YES	1,10	YES	2,23	YES	full	Wellhead	26,4	0,21
Reservoir liner	7" grade 13Cr, 29lbs/ft	2,21	YES	1,83	YES	2,94	YES	full	Shoe	90,2	0,78

	Various Well parameters										
Casing type	Setting depth [TVD]		Minimum Burst Strength		Minimum Collapse Resistance [bar]		Minimum tensional Strength [daN]				
	[m]	[ft]	[bar]	[psi]	[bar]	[psi]	[daN]	[MT]			
Surface Casing	1100	3609	119	1726	42	605	557909	569			
Intermediate Casing	1820	5971	195	2826	95	1378	475426	485			
Intermediate Liner	1000 – 1820	3280 – 5969,6	172	2499	95	1378	373459	381			
Production Casing	2365	7757	204	2959	174	2518	371406	379			
Production liner	2265 – 2900	7429,2 – 9512	214	3099	306	4438	243385	248			
Reservoir liner	2260 – 2625	7412,8 – 8610	252	3653	209	3037	127854	130			

Figure 19: Example of results

Figure 19 above shows a screenshot of the result page in the program. The uppermost table is presenting the results for the final casing and well design. This table lists which casing string is involved in the design and which grade of casing this is. in addition, various parameters that is relevant to each string is listed such as, design factors for burst, collapse and tension, if the well has reduced or full integrity, location of the weak point in the well, Maximum kick size that can be taken without fracturing the shoe, and lastly the maximum pressure gradient that the casing shoe can handle, which is based on the burst strength of the casing.

The next table in figure 19 contains some calculated values for the well in general based on already determined setting depths. It gives the user an overview of the minimum required casing strengths for burst, collapse and tension at the specific depths chosen, included the operator safety factors inserted in "inndata". These values are calculated from the worst-case loads obtained from the calculations. This is an especially resourceful function when picking the grade of casing for the different intervals determined.

Lastly figure 19 presents the user with a clear and informative graph on the relevant parameters involved for each criterion, for each specific casing string. The most important lines are completely filled, and the rest is dashed. As can be seen in the graphs, the important lines are the net burst/collapse loads, and the burst/collapse strength of the casing involved. This gives a clear picture if the net load exceeds that of the casing at any

given point on the casing. It has been deemed that the easiest way to present these graphs is to have one separate graph for each criterion on each casing.

5.3 Basic Excel and VBA functions

IF function

This is an extremely useful function integrated in basic excel that has been utilized throughout the whole design of this program to help achieve the result of a dynamic environment. The syntax for this formula is *"=IF (logical_test, [value_if_true], [value_if_false])"* Example of a simple IF function from the program is shown below:

$$=IF(C48="YES";'Intermediate liner'!D37;0)$$

This formula works so that if the value in cell J48 is the word "YES", it will return the value that is in D37 in the intermediate liner sheet, if the word is anything else than YES, it will return the value 0 (zero) in this example.

MAX/MIN functions

These functions are also frequently used throughout the program. They are especially useful in the casing load calculations where several loads are investigated, but only the highest value (maximum value) is required in further calculations. Example of a simple MAX function is shown below:

$$=MAX(D27:D28)$$

In this example, the cell containing the function will show the value from whichever cell that has the higher value. This example the cells to compare is D27 and D28.

VLOOKUP

The VLOOKUP function is an important function when it is required from the program to look for specific values in a table and then return another value connected to the initial value. The syntax for this function is "*=VLOOKUP (value, table, col_index, [range_lookup])"*. This was of particular importance when automating the biaxial collapse resistance so that the user doesn't have to manually look through a set of values. The function shown below is the one used for this application:

$$=VLOOKUP(C64;'Collapse vs Tension'!A3:B103;2;TRUE)$$

This example function works like this: Cell C64 is showing value 0,33. The function will then look through column A3 under the collapse vs tension sheet. A3:B103 is the limits for the entire area focused by the function. When the function finds the value 0,33 in column A3 (which is column 1 in the limit area) it will jump to the right and find the corresponding value. How far to the right it goes to look is determined by the next number in the function. Here it is the number 2, that means it will return the value that is in column 2. At the end of

the function the word "TRUE" is listed. This tells the function to look for the closest match instead of the exact match.

SetChartAxis function

This is a complex VBA function to automatically adjust the minimum and maximum x and y axis values on plots after the base data is altered. For some reason this is not a basic excel function available to its users. This is yet another important function to help create a program that is as dynamic as possible. The code/module for this function is added in Appendix A.1. The syntax used for this function is "*=setChartAxis(sheetName, chartName, MinOrMax, ValueOrCategory, PrimaryOrSecondary, Value)*" This function needs to be inserted anywhere in the same worksheet as the graph. In this program it is hidden in the background. An example of the usage of this function in the program is shown below:

```
=setChartAxis("Results";"Chart 10";"Max";"X";"Primary";E92)
```

As mentioned, this function must be inserted in a cell located in the same worksheet as the graph, and in this example that is in the "Results" sheet. Next step is to insert the name of the graph, here it's "chart 10". The next two values tell the function that it is the "max" value on the "X" axis that is focused. Primary or secondary also tells the program which axis is in focus. The last number, here E92, is where the program will find this maximum value which the axis will be adjusted according to. 4 of these function strings is needed for every chart. Min and max for X-axis, and min and max for Y-axis

6 Case study

6.1 Aim of the study

The main aim for the study is to test the program on real world wells to ensure that it can handle different wells with different parameters and casing setups. Secondary aim for the study is to use the program to optimize said wells should the program identify flaws in the design. The test wells that will be investigated are mainly exploration wells from different companies, so a production scenario will be simulated, where a setting depth for the production packer must be determined as well as the design of a reservoir liner to fully utilize the program. Unfortunately, excel data on pore pressure and fracture gradients has not been obtained for any of the wells, only gradient plots which will be manually read. This means that the automatic gathering of pore pressures and fracture gradients based on the inserted setting depth of the casing will not be evaluated in this study.

6.2 Procedure

A step by step procedure on the evaluation of the wells are as followed:

Stage 1:

- Data gathering from the drilling program for the well under investigation. All the input fields in "inndata" must be identified in the program, included the listed data on casing grades that is or is planned to use in the well by the operator.
- Simulate a production casing scenario by designing a production packer at a realistic level inside the production casing/liner.
- If there is a reservoir liner planned in the program, simulate this under production. If there is no reservoir liner planned, but a contingency reservoir liner exists, use this liner. If the drilling program includes no reservoir liner at all, Find a setting depth, and design this from scratch in stage 2 using the well results.
- Check the relevant drop-down options in "inndata" to make sure that the right calculations are conducted for the given well.
- Evaluate if the program works by checking if returned values makes sense or if any errors has occurred. If returned values makes sense -> Proceed.
- Evaluate and report results on each string separately

Stage 2:

- If any flaws in the casing design is reported by the program, optimize it by adjusting setting depths, and/or casing grades to ensure well integrity in accordance with operator safety factors.

6.3 Base parameters for all wells

All strings will be subject to a Well Integrity evaluation where a kick margin is calculated and the weak point in the well is identified. Drillstring outer diameter is assumed to be 5,6" if nothing else is specified. Steel density is assumed 7,80 s.g. if nothing else is specified.
 Base parameters will be applied to the various strings as follows:

Surface Casing:

Criteria evaluated for the surface casing:

- BURST: Post-installation: Formation fluid filled casing.
    o Assumptions: Seawater behind casing only mobile phase (cement has been settled), reduction due to Wear, formation fluid gradient.
- COLLAPSE: Installation: Loading during cementing
    o Assumptions: Cement slurry behind casing
- COLLAPSE: Installation: Well fluid loss to a thief zone
    o Assumptions: Inside fluids drops until BHP is equivalent to a sea water column, adjusted for biaxial stress.
- TENSION: Weight of the casing in mud.
    o Assumptions: Max tensile forces occurs during installation so not adjustment for wear. Bending effects included.

Intermediate Casing

Criteria evaluated for the intermediate casing:

- BURST: Post-installation: Formation fluid filled casing
    o Assumptions: Seawater behind casing, adjusted for wear, formation fluid gradient.
- BURST: Post-installation of an intermediate liner: Formation fluid filled casing.
    o Assumptions: Seawater behind casing, adjusted for wear, formation fluid gradient from next open hole after liner.
- COLLAPSE: Installation: Well fluid loss to a thief zone.
    o Assumptions: Thief zone at the bottom of the well, outside fluid is mud, inside mud stabilizes at hydrostatic water pressure, air inside casing above mud.
- COLLAPSE: Post-installation/installation of liner: Well fluid loss to a thief zone
    o Assumptions: Thief zone at the bottom of liner well, rest is same as for the above assumptions.
- TENSION: Weight of the casing in mud.
    o Assumptions: Max tensile forces occurs during installation so not adjustment for wear. Bending effects included.

Intermediate Liner:

Criteria evaluated will be the same as for the intermediate liner.

Production Casing:

Criteria evaluated for the production casing:

- BURST: Post-Installation: Formation fluid filled casing.
  - o Assumptions: Seawater behind casing, adjusted for wear, formation fluid gradient from next open hole.
- BURST: Post-Installation of a production liner: Formation fluid filled casing.¨
  - o Assumptions: Seawater behind casing, adjusted for wear, formation fluid gradient from next open hole after the production liner.
- BURST: Production: Leaking tubing
  - o Assumptions: Tubing leak just below the wellhead, Pressure inside tubing will act on outside, annulus filled with completion fluid, just above packer depth will experience highest burst load.
- COLLAPSE: Installation: Well fluid loss to a thief zone
  - o Assumptions: Thief zone at the bottom of the well, outside fluid is mud, inside mud stabilizes at hydrostatic water pressure, air inside casing above mud.
- COLLAPSE: Post-installation/installation of liner: Well fluid loss to a thief zone
  - o Assumptions: Thief zone at the bottom of liner well, rest is same as for the above assumptions.
- COLLAPSE: Production: Plugged perforations.
  - o Assumptions: Only calculated if the casing has perforations , external pressure is formation pressure, internal pressure is reservoir formation fluid density.
- TENSION: Weight of the casing in mud.
  - o Assumptions: Max tensile forces occurs during installation so not adjustment for wear. Bending effects included.

Production Liner:

Criteria evaluated will be the same as for the intermediate liner.

Reservoir Liner:

Criteria evaluated for the reservoir liner:

- BURST: Production: Bullheading.
  - o Assumptions: Perforations may plug during bullheading, external fluid is seawater, bullheading fluid is formation fluid, adjusted for corrosion below packer
- BURST: Production: leaking tubing.
  - o Assumptions: Production packer set in top section of the reservoir liner, tubing leak just below wellhead, pressure inside will act on outside, annulus filled with completion fluid, adjusted for corrosion below packer.
- COLLAPSE: Production: Plugged perforations

- o Assumptions: External pressure is formation pressure; internal pressure is formation fluid density.
  - TENSION: Weight of the casing in mud.
    - o Assumptions: Max tensile forces occurs during installation so no adjustment for wear. Bending effects included.

6.4   Case #1: Well X1

6.4.1   General Well info

Location:	Norwegian Sea (Offshore)
Well classification:	Appraisal
Formation fluid:	Gas condensate
Water depth:	300 m
Air gap:	30 m
Top of Reservoir:	4500
Wellhead design pressure:	15000 psi / 1034 bar
Drillpipe OD:	5,5 in

Operator safety factors: NORSOK

Burst:	1,10
Collapse:	1,10
Axial:	1,25

6.4.2 Well Schematic and pressure gradients
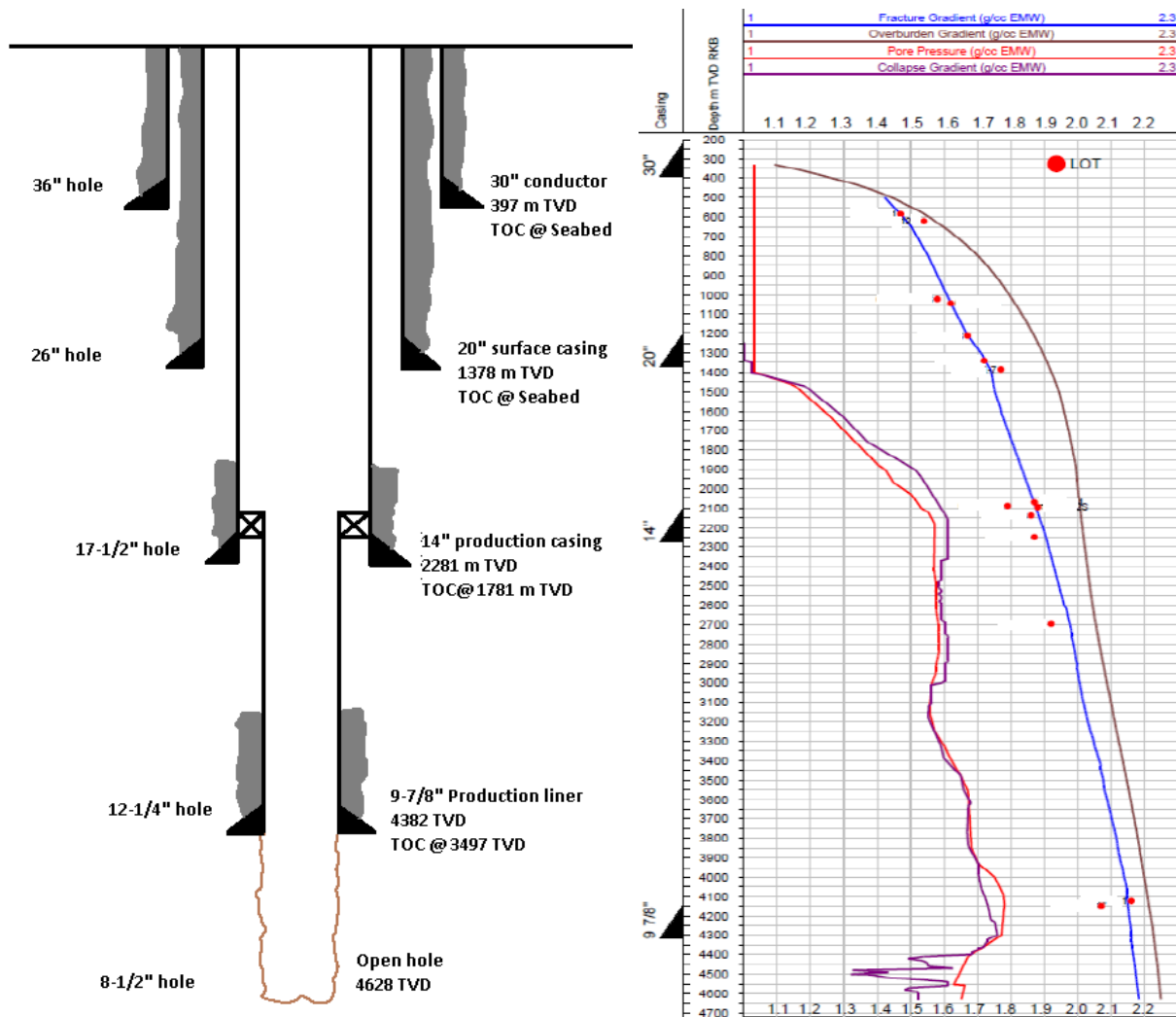
Figure 20: Well Schematic and pressure gradients X-1

6.4.3 Inndata for each string

20" surface casing:

Design parameters:

Air gap:	30 m
Seabed:	300 m
Depth of casing:	1378 m
TOC lead:	300 m
TOC tail:	1278 m
Next open hole section:	2284 m
Fracture gradient, casing shoe:	1,73 s.g.
Pore pressure gradient, casing shoe:	1,03 s.g.
Pore pressure gradient, open hole:	1,56 s.g.
Formation fluid density:	0,32 s.g.

Mud density:	1,35 s.g.
Mud density, next open hole:	1,60 s.g.
Cement density, lead:	1,56 s.g.
Cement density, tail:	1,90 s.g.

Casing data:	20" grade X-56, 129,3lb/ft
Weight:	192,4 kg/m
OD tube:	20,000 in
ID tube:	18,750 in
Burst strength:	211 bar
Collapse resistance:	100 bar
Pipe body yield strength:	834546 daN
Bending tension:	150000 daN

14" production casing:

Design parameters:

Air gap:	30 m
Seabed:	300 m
Depth of casing:	2281 m
TOC:	300 m
Next open hole section:	4385 m

Fracture gradient, casing shoe:	1,91 s.g.
Pore pressure gradient, casing shoe:	1,56 s.g.
Pore pressure gradient, open hole:	1,78 s.g.
Formation fluid density:	0,32 s.g.
Mud density:	1,60 s.g.
Mud density, next open hole:	1,81 s.g.
Cement density, lead:	1,92 s.g.
Completion fluid density	1,15 s.g.

Casing data:	14" grade TN-125 SS, 114lb/ft
Weight:	169,7 kg/m
OD tube:	14,000 in
ID tube:	12,400 in
Burst strength:	862 bar
Collapse resistance:	597 bar
Pipe body yield strength:	1844632 daN
Bending tension:	50000 daN

9-7/8" production liner:

<u>Design parameters:</u>

Air gap:	30 m
Seabed:	300 m
Depth of liner:	4260 m
Top of liner:	2181 m
TOC:	3497 m
Production packer (Assumed)	4000 m
Next open hole section:	4628 m
Fracture gradient, liner shoe:	2,16 s.g.
Pore pressure gradient, liner shoe:	1,78 s.g.
Pore pressure gradient, open hole:	1,67 s.g.
Formation fluid density:	0,32 s.g.
Mud density:	1,81 s.g.
Mud density, next open hole:	1,81 s.g.
Cement density, lead:	2,00 s.g.
Completion fluid density	1,15 s.g.

<u>Casing data:</u>   9-7/8" grade P-110, 66,9lb/ft

Weight:	99,6 kg/m
OD tube:	9,875 in
ID tube:	8,539 in
Burst strength:	776 bar
Collapse resistance:	898 bar
Pipe body yield strength:	945361 daN
Bending tension:	30000 daN

7" reservoir contingency liner

<u>Design parameters:</u>

Air gap:	30 m
Seabed:	300 m
Depth of liner:	4550 m
Top of liner:	4200 m
TOC:	4260 m
Next open hole section:	4628 m
Fracture gradient, liner shoe:	2,18 s.g.
Pore pressure gradient, liner shoe:	1,67 s.g.
Pore pressure gradient, open hole:	1,67 s.g.
Formation fluid density:	0,32 s.g.

Mud density:		1,81 s.g.
Mud density, next open hole:		1,81 s.g.
Cement density, lead:		2,00 s.g.
Completion fluid density		1,15 s.g.
<u>Casing data:</u>	7" grade P-110, 35lb/ft	
Weight:		52,1 kg/m
OD tube:		7,000 in
ID tube:		6,004 in
Burst Strength:		945 bar
Collapse resistance:		899 bar
Pipe body yield strength:		497197 daN

6.4.4   Results from original data

Table 5: Well X-1: Casing design results

Casing type	Casing grade	Burst - OK?		Collapse - OK?		Tension - OK?	
Surface Casing	20"grade X56, 129,3lb/ft	0,74	NO	1,78	YES	1,16	NO
Production Casing	14"grade TN-125 SS, 114lb/ft	1,28	YES	1,62	YES	1,42	YES
Production liner	9-7/8"grade P-110,66,9lb/ft	1,41	YES	2,42	YES	1,45	YES
Reservoir liner	7"grade P-110, 35lb/ft	1,66	YES	1,07	NO	1,96	YES

Casing type	Casing grade	Well Integrity	Weak Point	Max Kick Size [m3]	Max Frac.grad.
Surface Casing	20"grade X56, 129,3lb/ft	Reduced	Shoe	29,6	1,67
Production Casing	14"grade TN-125 SS, 114lb/ft	Reduced	Shoe	14,7	3,78
Production liner	9-7/8"grade P-110,66,9lb/ft	full	Shoe	30,6	2,17
Reservoir liner	7"grade P-110, 35lb/ft	full	Shoe	127,3	4,76

Table 6: Well X-1: Well parameters and minimum requirements for casing strengths.

Casing type	Setting depth [TVD]		Minimum Burst Strength		Minimum Collapse Resistance [bar]		Minimum tensional Strength [daN]	
	[m]	[ft]	[bar]	[psi]	[bar]	[psi]	[daN]	[MT]
Surface Casing	1378	4521	282	4095	62	898	899911	918
Production Casing	2281	7482	667	9677	362	5244	1459344	1488
Production liner	2181 - 4260	153,68 - 13972	347	5039	362	5244	734828	749
Reservoir liner	4200 - 4550	13776 - 14924	564	8181	662	9604	316341	323
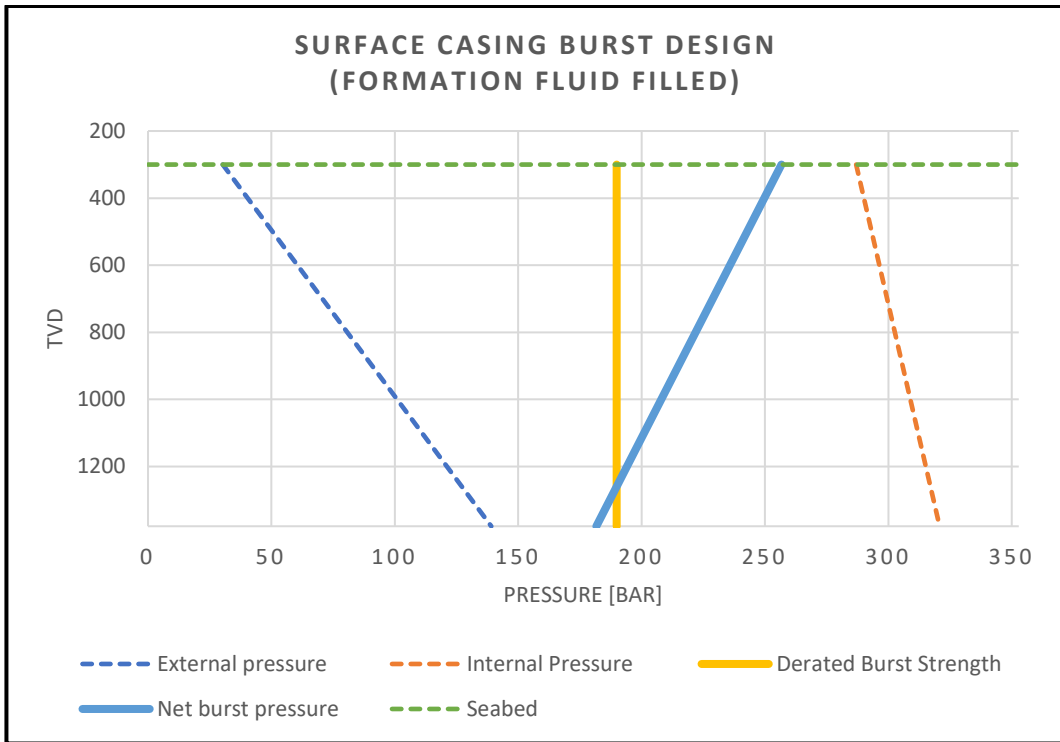
Figure 21: Well X-1: Surface casing burst design – Formation fluid filled
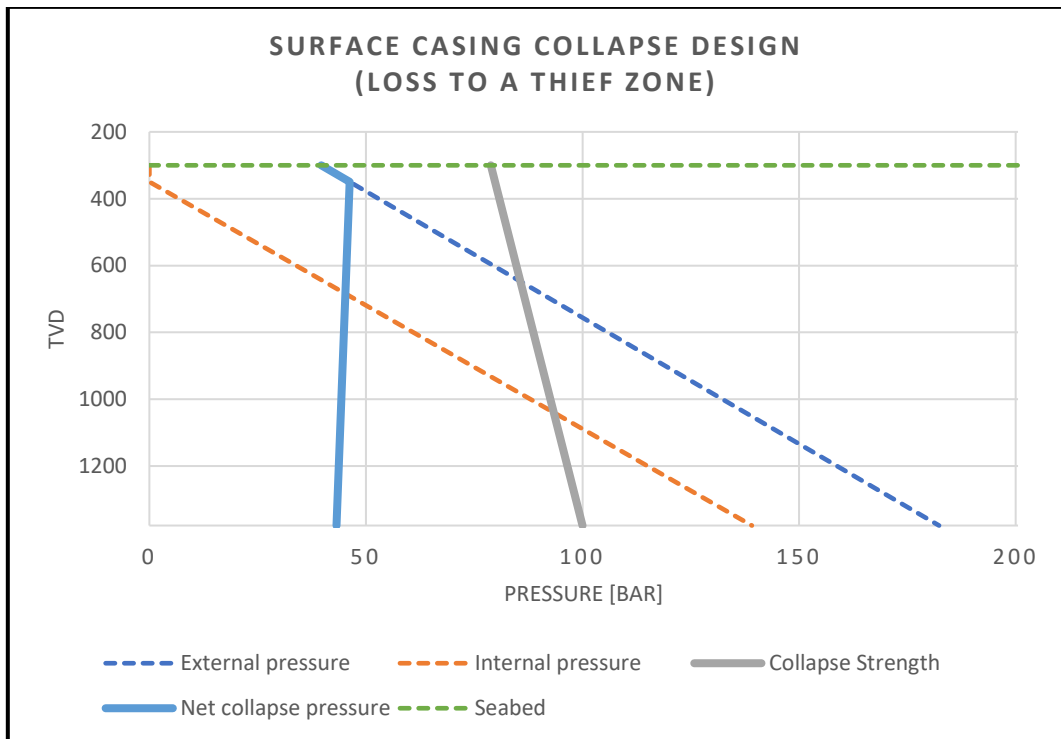
Figure 22: Well X-1: Surface casing collapse design – Loss to a thief zone
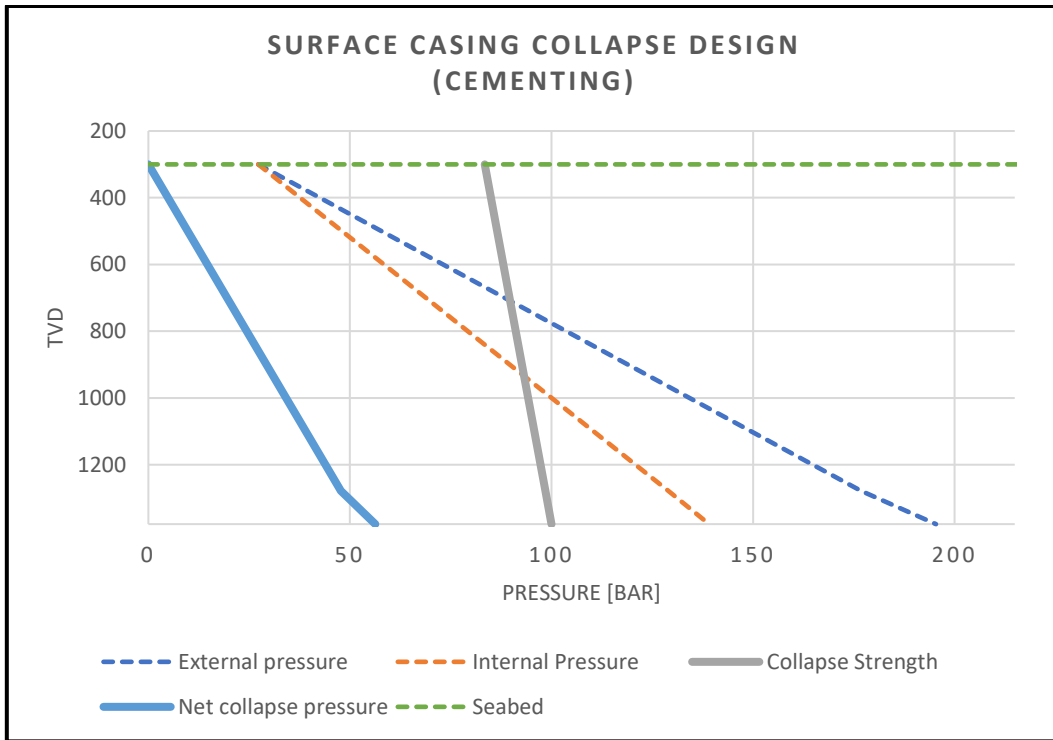
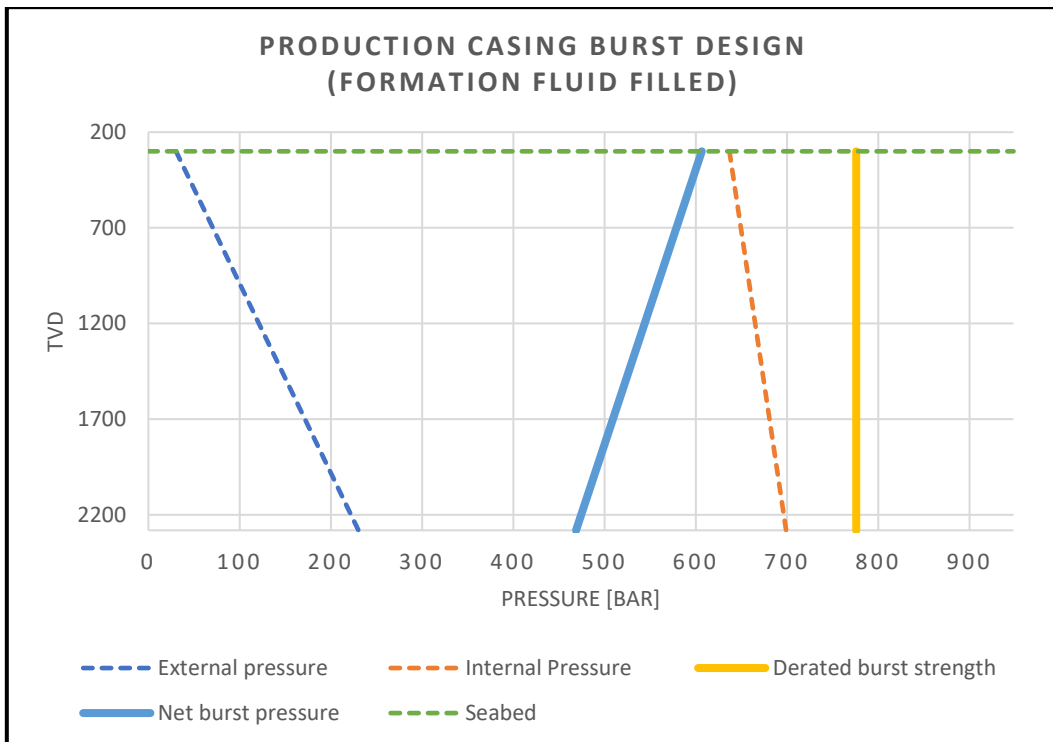*Figure 23: Well X-1: Surface casing collapse design – Cementing*

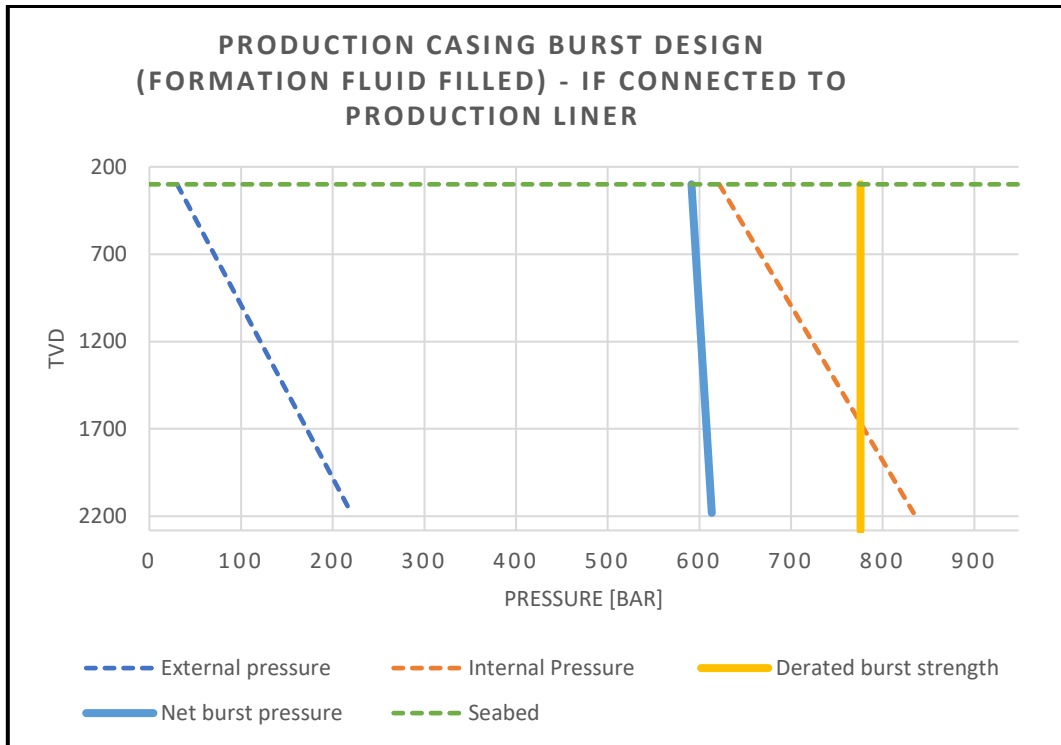*Figure 24: Well X-1: Production casing bust design – Formation fluid filled casing*

Figure 25: Well X-1: Production casing burst design – Formation fluid filled casing, from connected liner
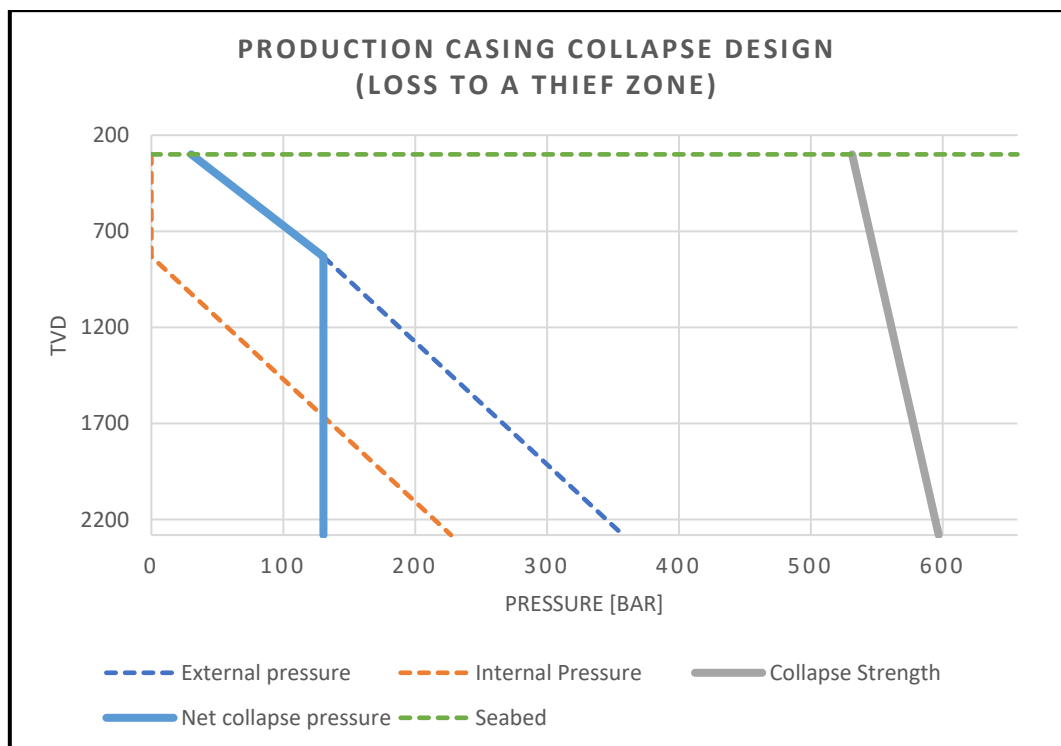

Figure 26: Well X-1: Production casing collapse design – Loss to a thief zone
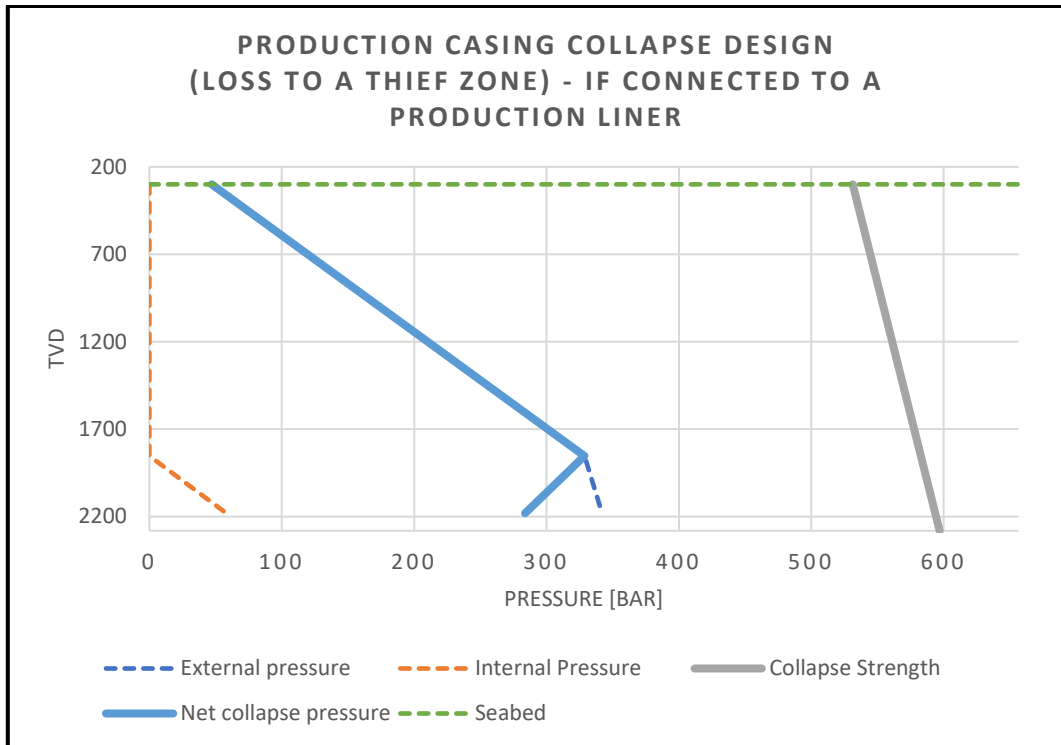
Figure 27: Well X-1: Production casing collapse design – Loss to a thief zone, from connected liner
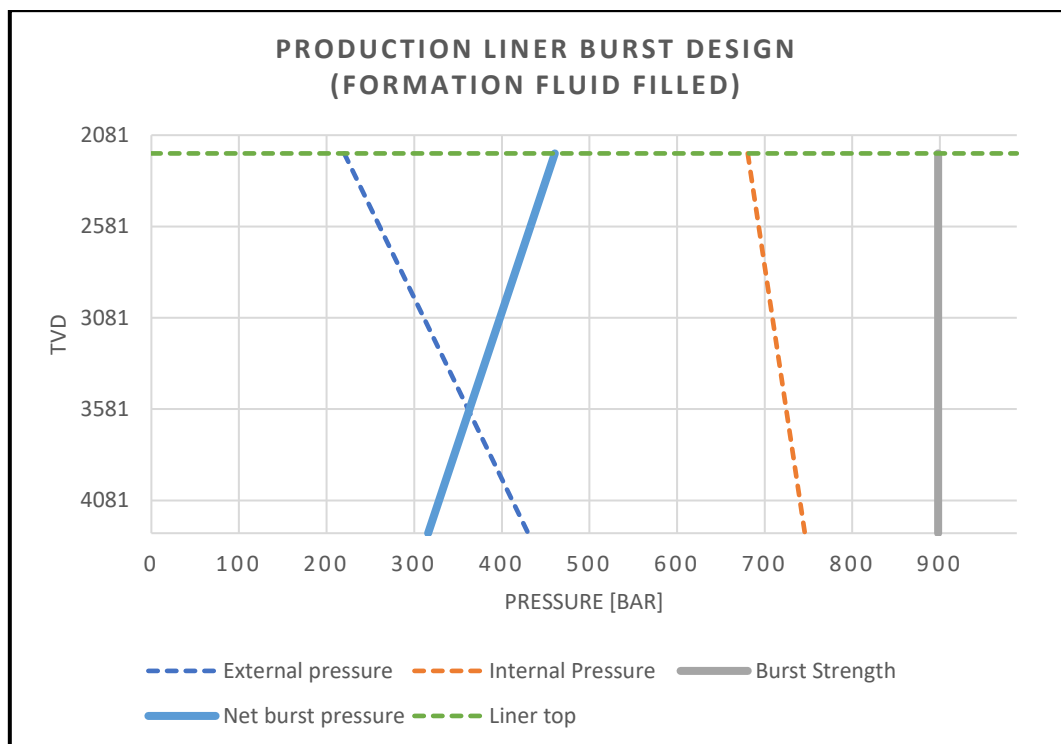
Figure 28: Well X-1: Production liner burst design – Formation fluid filled
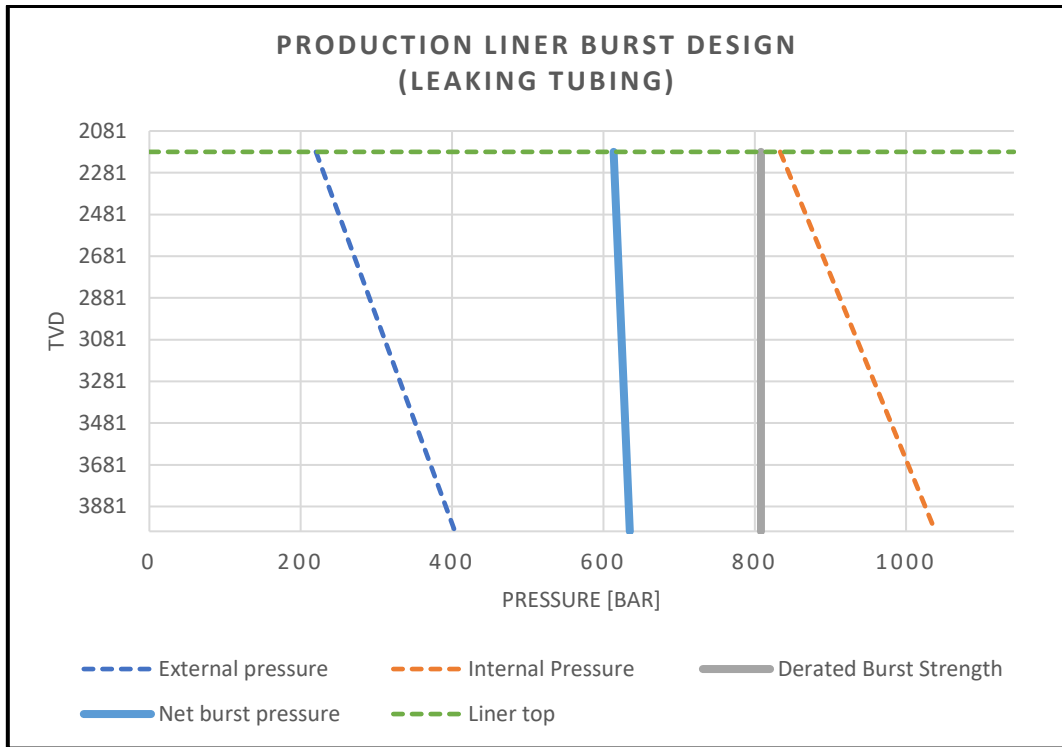
Figure 29: Well X-1: Production liner burst design – Leaking tubing
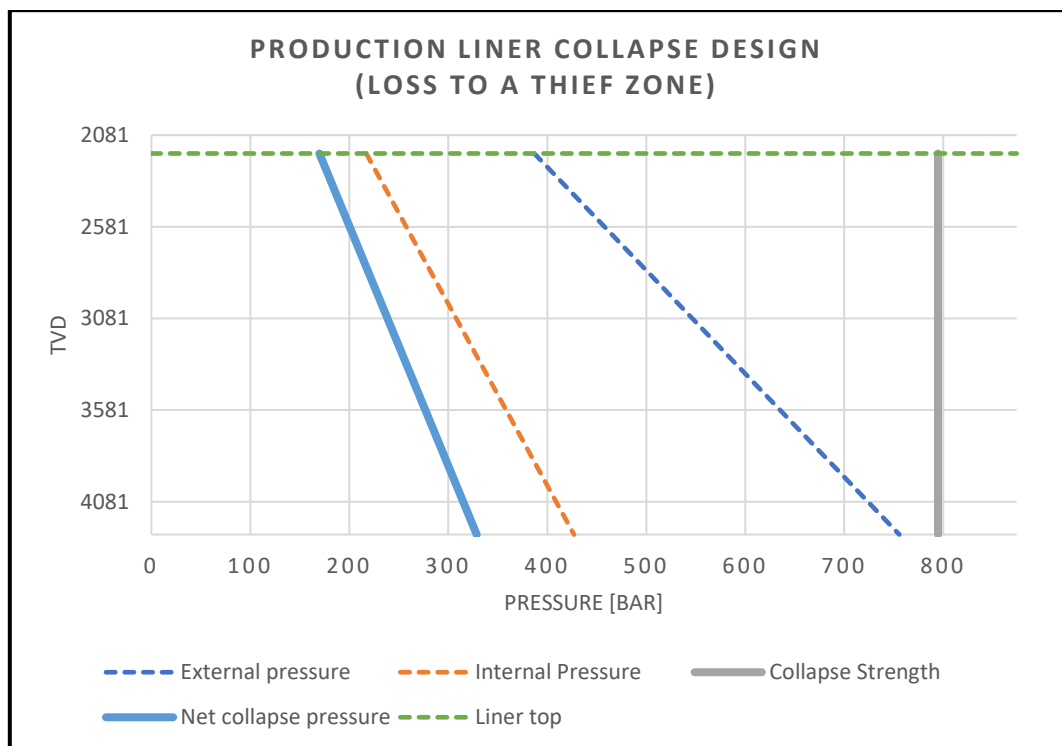
Figure 30: Well X-1: Production liner collapse design - Loss to a thief zone
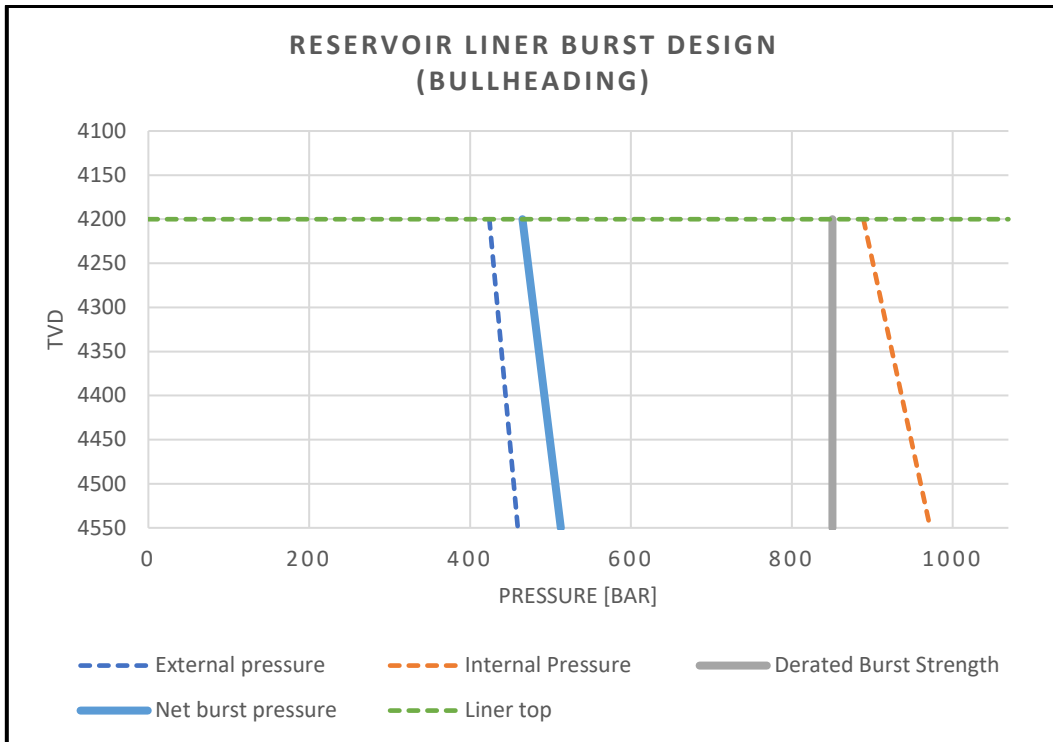
Figure 31: Well X-1; Reservoir liner burst design - Bullheading
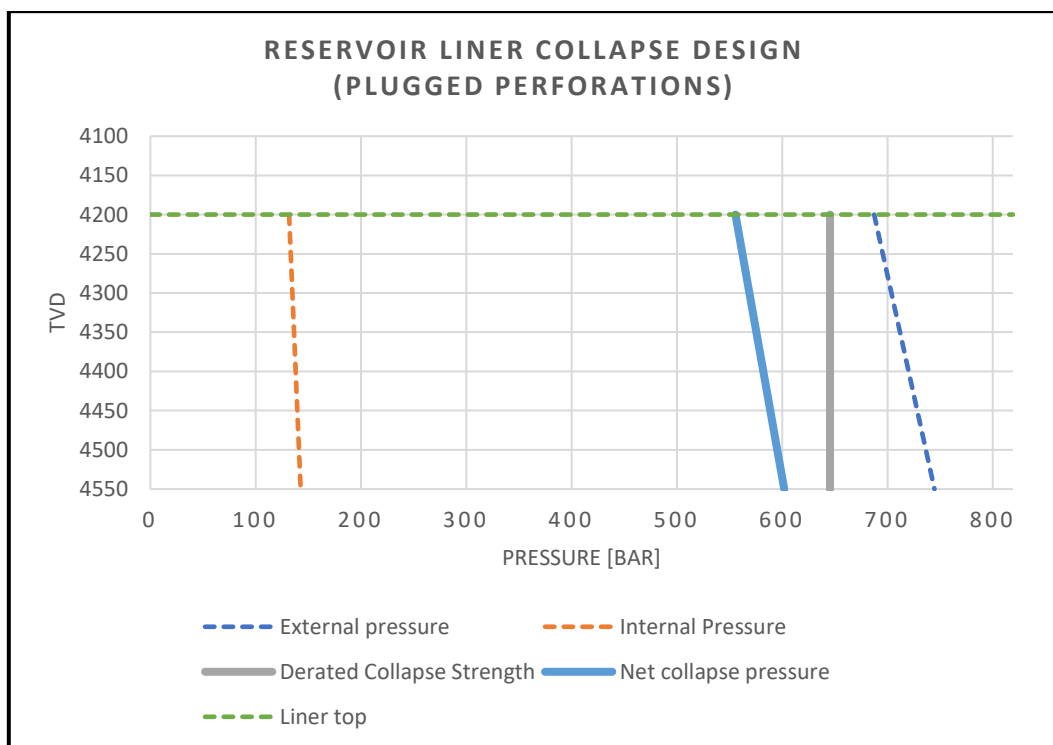
Figure 32: Well X-1: Reservoir liner collapse design – Plugged perforations

6.4.5 Discussion and optimization

The program works as expected and an evaluation of these results will therefore be conducted.

<u>Surface casing:</u>

As shown by the results, the surface casing falls short when it comes to burst strength and tension. The burst criterion that fails the casing is the formation fluid filled casing, gas kick, in this situation. One of the reasons for this may be because the criterion is based on a completely filled casing and is therefore very conservative. Another reason can be that the operator for this well works with different criteria for evaluating their wells, and in their calculations deemed this casing sufficient.

The well integrity evaluation for this well shows that the casing has reduced well integrity in the event of a formation filled casing. This means that the if this event would occur, the shoe would not withstand the pressure and an underground blowout would likely be the result.

Because of this the next step is to look at the kick margin, and in this case the kick margin is 29,6 m³ which is sufficient according to the operator's requirements.

The program reports that the weak point in the well is at the casing shoe, which means that the formation would fracture before reaching the casing shoe. As explained earlier under the well integrity section, it is desired to have the weak point at the shoe and not at the wellhead.

The program further reports that the minimum requirement for burst strength (after reduction) is 282 bar, which means that the minimum requirement for factory burst strength is approximately 315 bar to be able to be within the safety factor of 1.10

To optimize this, the casing table is used, and the search is narrowed down to 20" surface casings with burst strengths above 315 bar. The suggested surface casing to use is: 20'' grade L-80, 169lb/ft which has a burst strength of 392 bar. Inserting this casing into the program results in the following:

Table 7: Well X-1: Surface casing identified for design optimization.

Casing grade	Burst - OK?		Collapse - OK?		Tension - OK?	
20'' grade L-80, 169lb/ft	1,37	YES	3,69	YES	1,74	YES

This fixed the problem by increasing the design factor to 1,37 for burst and in the same time it increased the tension design factor so that it as well is within limits. The choice of casing grades is of course also governed by availability and price of, but that aspect of the design is not included in this thesis.

Production casing:

The production casing is within limits with regards to safety factors, but the program reports it to have reduced well integrity. This means that with a completely formation fluid filled casing, the shoe would not be able to withstand the pressure. Because of this, a kick margin is investigated and the program reports that to be 14,7 m^3 which is within the required limits of the operator. Weak point is reported to be at the shoe, which is where it should be.

Production liner:

The production liner has produced acceptable results in this program. The program reports it to have full well integrity. Design factors have satisfactory safety margins with respect to the operator safety factors. In this well the production packer is assumed placed in the interval of this liner and it has passed the leaking tubing criterion. Kick margin and max frac gradient is also within limits.

Reservoir liner:

The program reports acceptable results for the liner with regard to integrity, weak point, kick size and maximum frac grad, but it fails the liner on the collapse design factor, which is here reported to be 1,07. The operator's safety factor requirement for collapse resistance is 1,10. As for the surface casing, the operator may work under different conditions with regard to criteria evaluated in the casing design.

The maximum collapse load for the reservoir liner occurs if the perforations gets plugged during production. In this simulation it is assumed that the liner has 10% corrosion of the walls due to formation liquids. The production packer is placed in the above production liner, so the assumption is that the whole of the liner is affected by this corrosion. By just a minor reduction of the corrosion percentage from 10% down to 9%, the design factor changes to 1,11 which is an acceptable value according to the safety factors. So this really comes down to the assumed corrosion percentage that the operator plans for, and if the casing is designed for corrosive environments.

Should however the base required criterion for corrosion over time be 10%, a stronger liner will have to be put in its place. The program reports that the minimum collapse resistance, after derating, is 662 bar. This results in the need for a liner with minimum factory collapse resistance of at least 925 bar. Using this minimum requirement in casing data to look for the lowest grade liner that satisfies this, while making sure that it does not affect the burst and tension requirements, the following liners is reported to be sufficient:

7" grade S-95, 38lb/ft
7" grade T-95, 38lb/ft
7" grade H2S-95, 38lb/ft
7" grade C-95, 38lb/ft
7" grade C-95, 38lb/ft
7" grade S-95, 38lb/ft
7" grade T-95, 38lb/ft
7" grade H2S-95, 38lb/ft

Again, no focus is directed towards the price, availability or delivery times of the mentioned liners. Very often operators have a set of casing to work with and simply cannot pick and choose from every liner available on the market.

6.5   Case #2: Well X2

6.5.1   General Well info

Location:	Mediterranean Sea (Offshore)
Well classification:	Exploration
Formation fluid:	Gas condensate
Water depth:	1010 m
Air gap:	25 m
Top of Reservoir:	5000 (assumed)
Wellhead design pressure:	15000 psi / 1034 bar
Drillpipe OD:	5,5 in

Operator safety factors:	
Burst:	1,10
Collapse:	1,10
Axial:	1,15

6.5.2 Well Schematic and pressure gradients
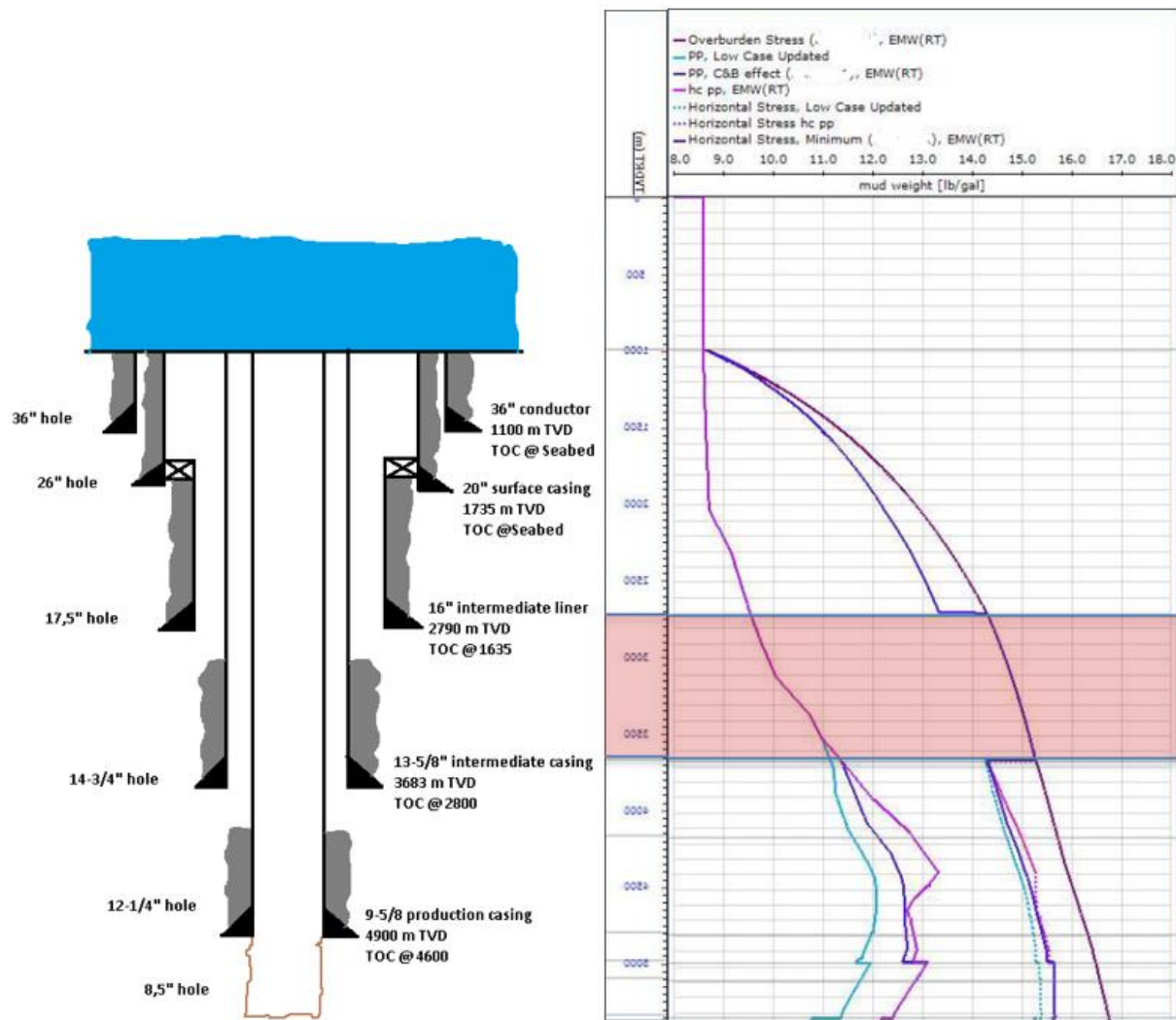
Figure 33: Well schematic and pressure gradients X-2

6.5.3 Inndata for each string

20" surface casing:

Design parameters:

Air gap:	25 m
Seabed:	1010 m
Depth of casing:	1735 m
TOC lead:	1010 m
TOC tail:	1685 m
Next open hole section:	2790 m
Fracture gradient, casing shoe:	1,40 s.g.
Pore pressure gradient, casing shoe:	1,04 s.g.
Pore pressure gradient, open hole:	1,15 s.g.

Formation fluid density:	0,50 s.g.
Mud density:	1,08 s.g.
Mud density, next open hole:	1,20 s.g.
Cement density, lead:	1,50 s.g.
Cement density, tail:	1,82 s.g.

Casing data: 20" grade N-80, 133lb/ft

Weight:	197,9 kg/m
OD tube:	20,000 in
ID tube:	18,730 in
Burst strength:	307 bar
Collapse resistance:	110 bar
Pipe body yield strength:	1374945 daN
Bending tension:	100000 daN

16" intermediate liner:

Design parameters:

Air gap:	25 m
Seabed:	1010 m
Depth of liner:	2790 m
Top of liner	1635 m
TOC:	1635 m
Next open hole section:	3683 m

Fracture gradient, liner shoe:	1,82 s.g.
Pore pressure gradient, liner shoe:	1,15 s.g.
Pore pressure gradient, open hole:	1,33 s.g.
Formation fluid density:	0,50 s.g.
Mud density:	1,20 s.g.
Mud density, next open hole:	1,50 s.g.
Cement density, lead:	1,56 s.g.

Casing data:	16" grade L-80, 84lb/ft
Weight:	125,0 kg/m
OD tube:	16,000 in
ID tube:	15,010 in
Burst strength:	299 bar
Collapse resistance:	102 bar
Pipe body yield strength:	858061 daN
Bending tension:	50000 daN

13-5/8" Intermediate casing:

<u>Design parameters:</u>

Air gap:	25 m
Seabed:	1010 m
Depth of casing:	3683 m
TOC:	2800 m
Next open hole section:	4900 m
Fracture gradient, casing shoe:	1,82 s.g.
Pore pressure gradient, casing shoe:	1,33 s.g.
Pore pressure gradient, open hole:	1,44 s.g.
Formation fluid density:	0,50 s.g.
Mud density:	1,50 s.g.
Mud density, next open hole:	1,57 s.g.
Cement density, lead:	1,92 s.g.
Casing data:	13-5/8" grade P-110, 88,2lb/ft
Weight:	131,1 kg/m
OD tube:	13,630 in
ID tube:	12,375 in
Burst strength:	609 bar
Collapse resistance:	315 bar
Pipe body yield strength:	1249060 daN
Bending tension:	100000 daN

9-5/8" production casing:

<u>Design parameters:</u>

Air gap:	25 m
Seabed:	1010 m
Depth of casing:	4900 m
TOC:	4600 m
Production packer (assumed)	4750 m
Next open hole section:	5208 m
Fracture gradient, casing shoe:	1,82 s.g.
Pore pressure gradient, casing shoe:	1,44 s.g.
Pore pressure gradient, open hole:	1,43 s.g.
Formation fluid density:	0,50 s.g.
Mud density:	1,57 s.g.
Mud density, next open hole:	1,64 s.g.

Cement density, lead:	1,92 s.g.
Completion fluid density	1,15 s.g.
Casing data:	9-5/8" grade Q-125, 53,5lb/ft
Weight:	79,6 kg/m
OD tube:	9,625 in
ID tube:	8,535 in
Burst strength:	854 bar
Collapse resistance:	582 bar
Pipe body yield strength:	864289 daN
Bending tension:	100000 daN

6.5.4 Results from original data

Table 9: Well X-2: Casing design results

Casing type	Casing grade	Burst - OK?		Collapse - OK?		Tension - OK?	
Surface Casing	20"grade N-80, 133lbs/ft	1,52	YES	3,39	YES	2,54	YES
Intermediate Casing	13-5/8"grade P-110, 88,2lb/ft	1,37	YES	1,47	YES	1,64	YES
Intermediate Liner	16"grade L-80, 84lb/ft	1,25	YES	1,85	YES	1,86	YES
Production Casing	9-5/8"grade Q-125, 53,5lb/ft	1,65	YES	1,62	YES	1,29	YES

Casing type	Casing grade	Well Integrity	Weak Point	Max Kick Size [m]	Max Frac.grad.
Surface Casing	20"grade N-80, 133lbs/ft	Reduced	Shoe	106,1	1,85
Intermediate Casing	13-5/8"grade P-110, 88,2lb/ft	full	Shoe	88,4	1,90
Intermediate Liner	16"grade L-80, 84lb/ft	full	lhead (prior cas	120,3	1,34
Production Casing	9-5/8"grade Q-125, 53,5lb/ft	full	Shoe	36,9	2,01

Table 10: Well X-2: Well parameters and minimum requirements for casing strengths

| Casing type	Setting depth [TVD]		Minimum Burst Strength		Minimum Collapse Resistance [bar]		Minimum tensional Strength [daN]	
	[m]	[ft]	[bar]	[psi]	[bar]	[psi]	[daN]	[MT]
Surface Casing	1735	5692	200	2906	36	518	621504	634
Intermediate Casing	3683	12083	439	6365	189	2747	789978	806
Intermediate Liner	1635 - 2790	5362,8 - 9151,2	236	3425	54	782	476987	486
Production Casing	4900	16072	513	7438	288	4177	692140	706
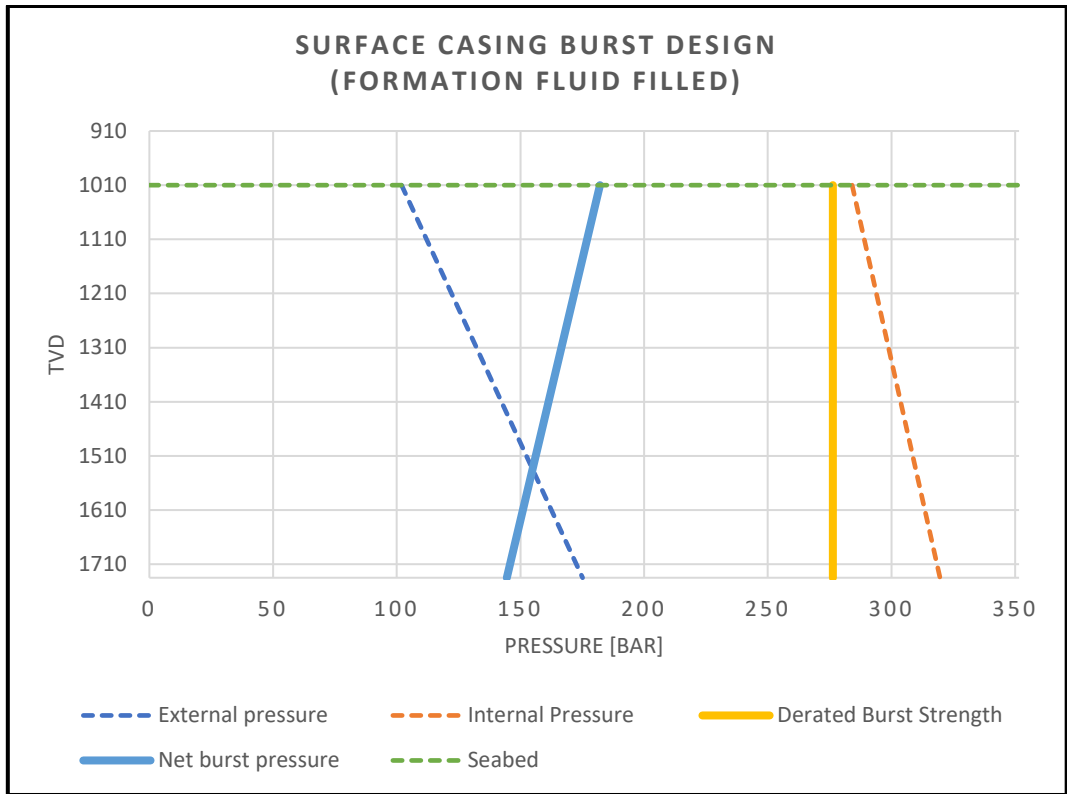
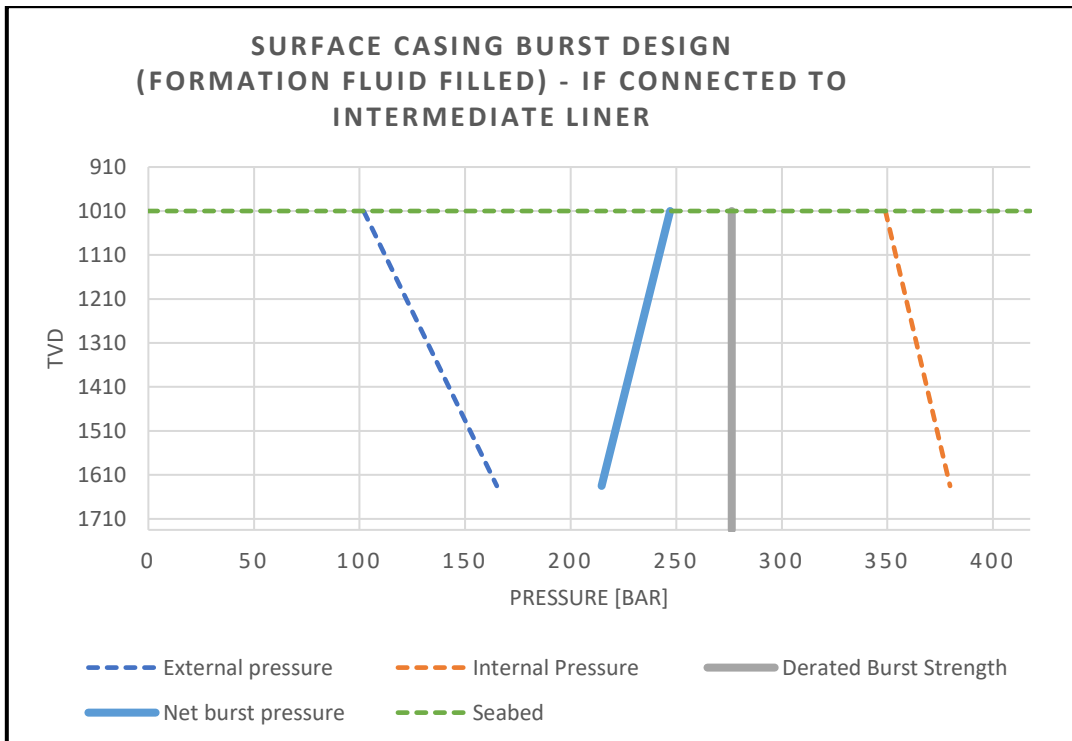*Figure 34: Well X-2: Surface casing burst design – Formation fluid filled casing*

Figure 35: Well X-2: Surface casing burst design – Formation fluid filled casing, from connecting liner.
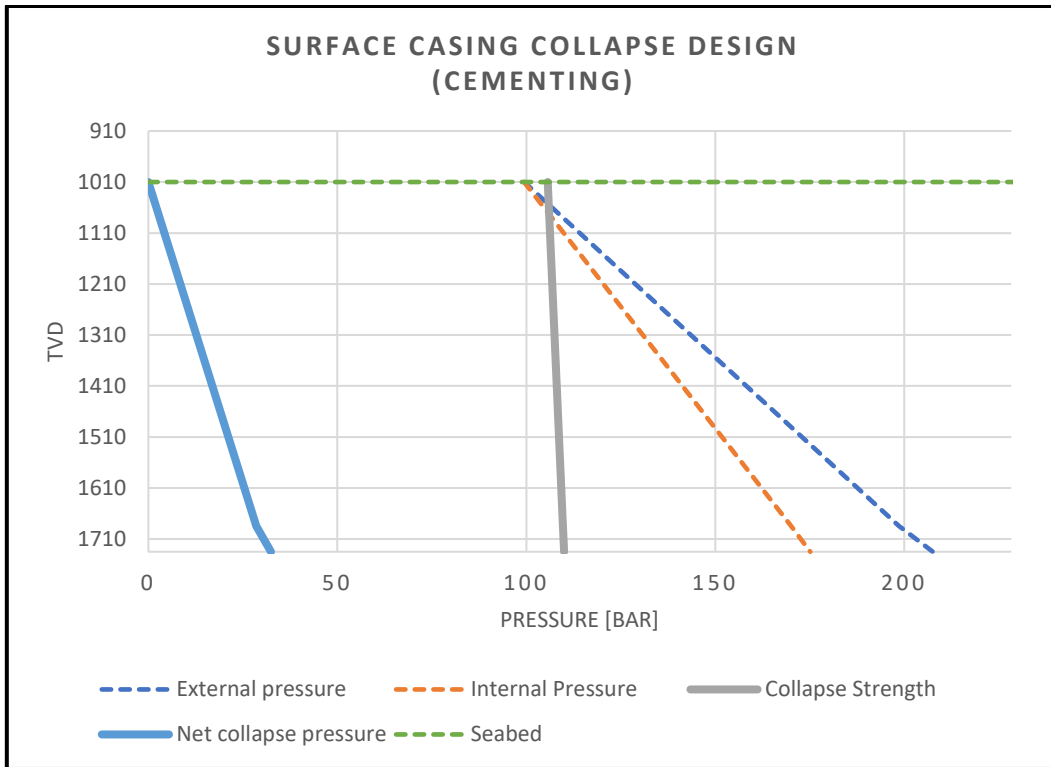
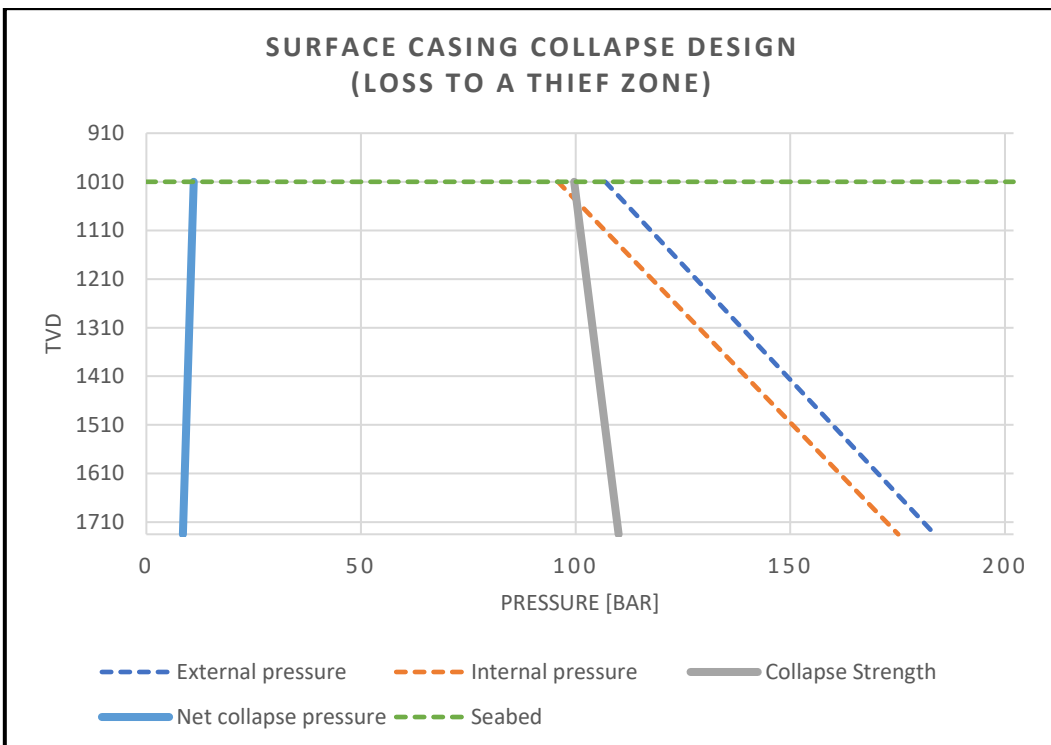*Figure 36: Well X-2: Surface casing collapse design - Cementing*

Figure 37: Well X-2: Surface casing collapse design – Loss to a thief zone
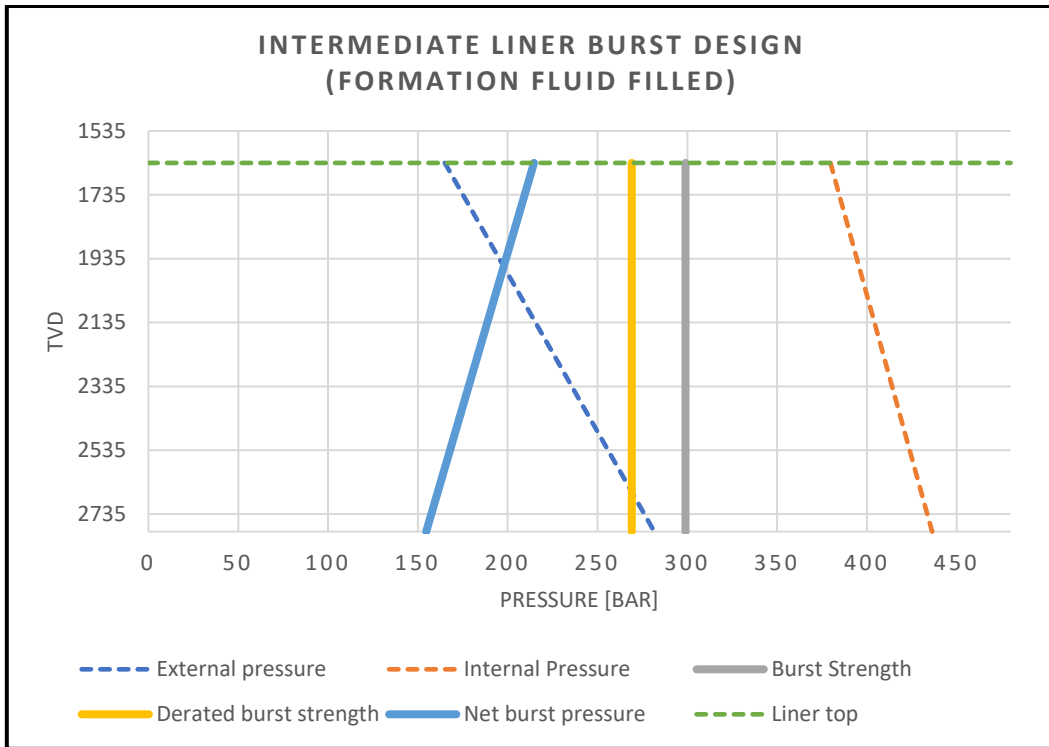
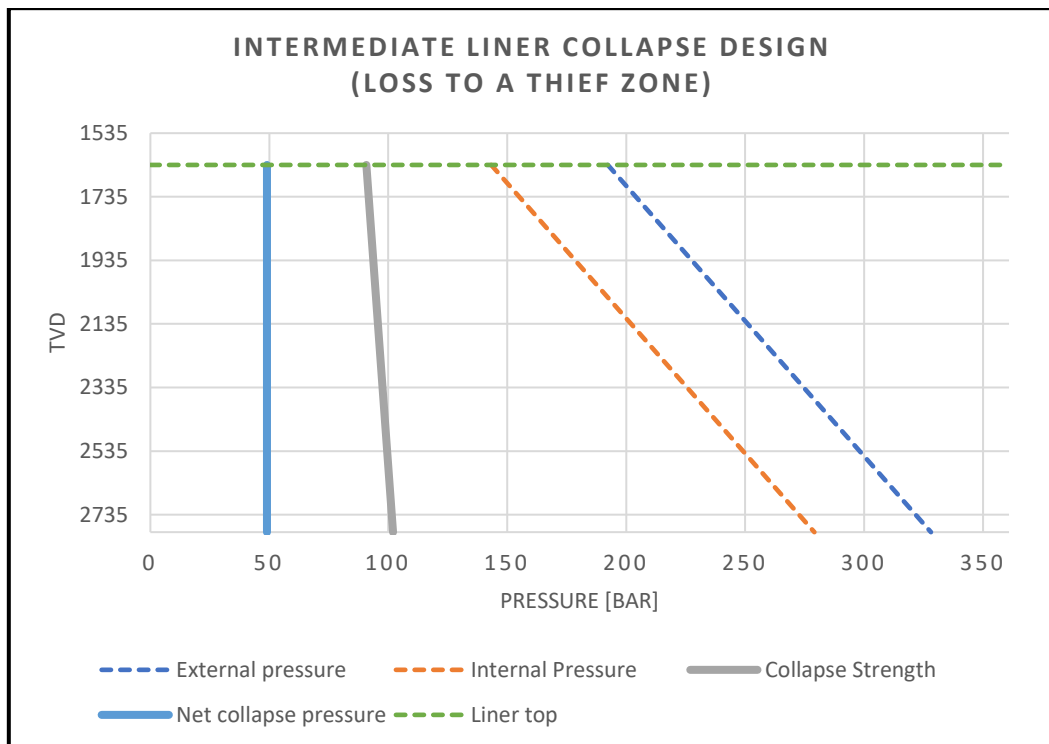*Figure 38: Well X-2: Intermediate liner burst design – Formation fluid filled casing*

Figure 39: Well X-2: Intermediate liner collapse design – Loss to a thief zone
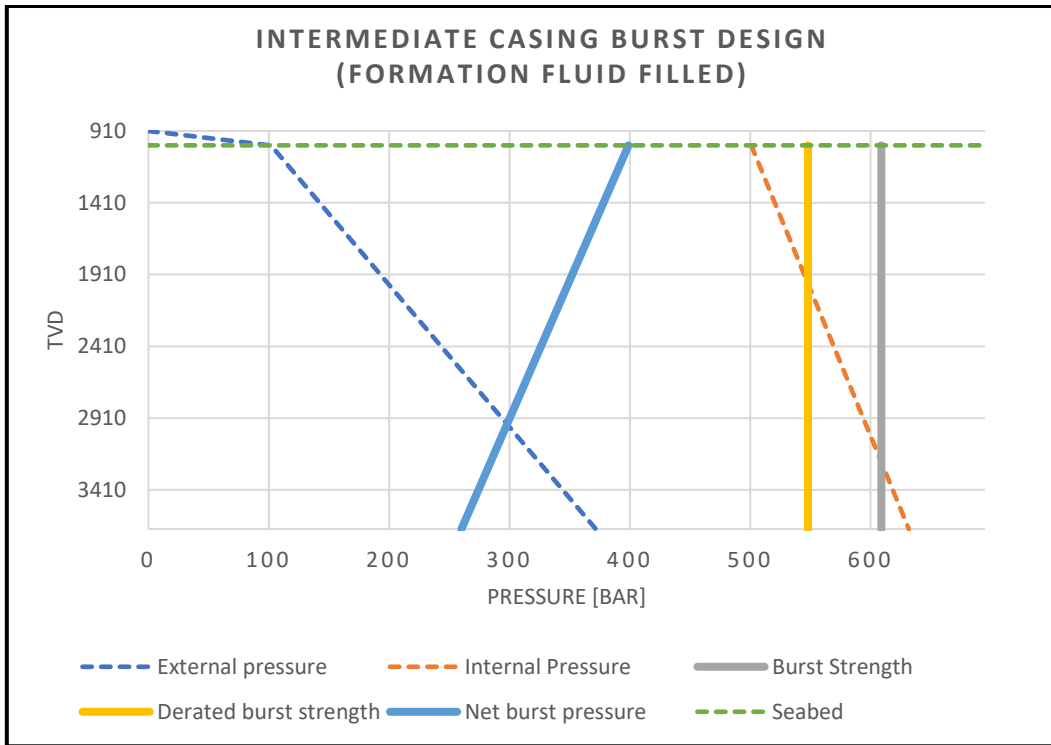
Figure 40: Well X-2: Intermediate casing burst design – Formation fluid filled casing.
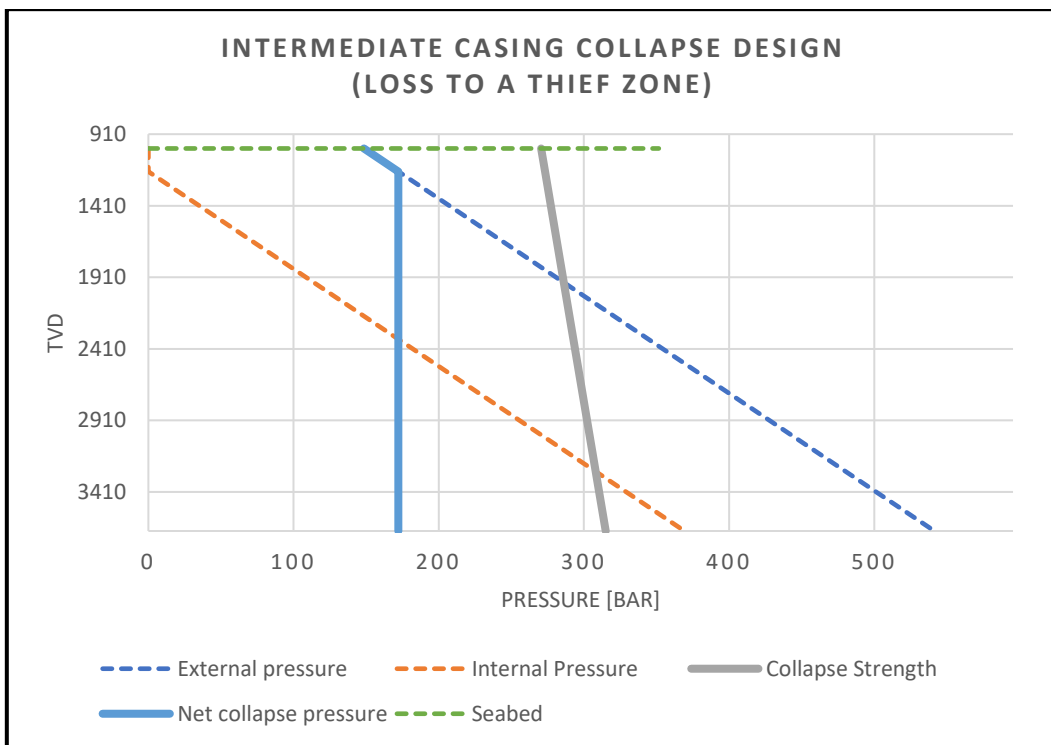

Figure 41: Well X-2: Intermediate casing collapse design – Loss to a thief zone.
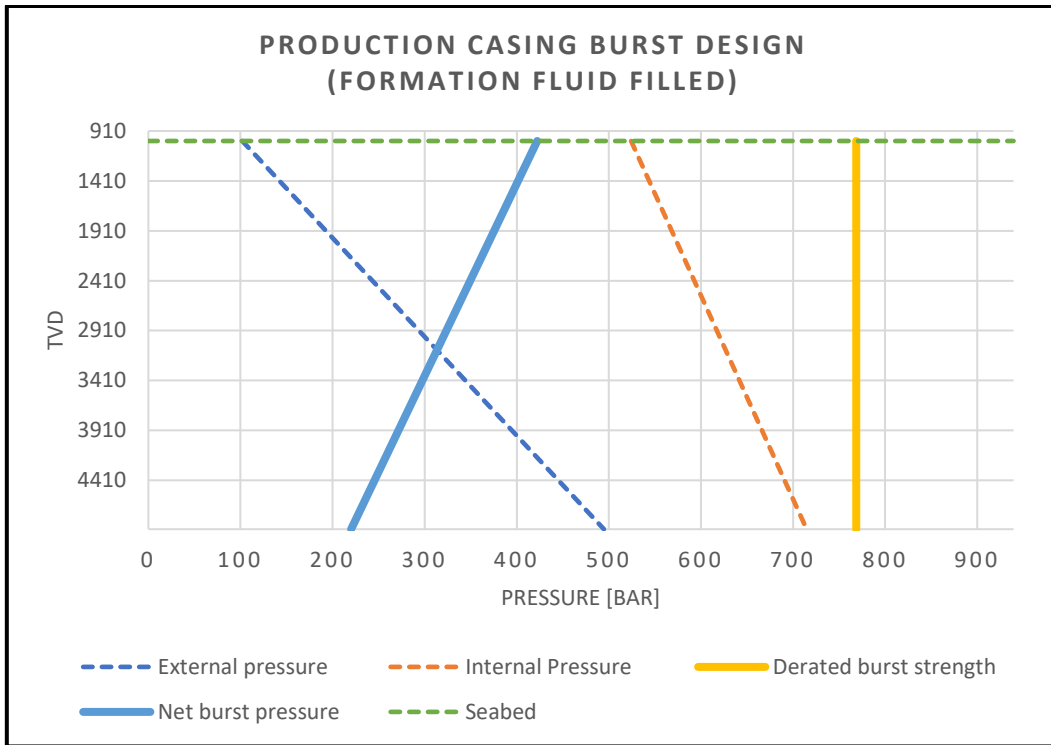
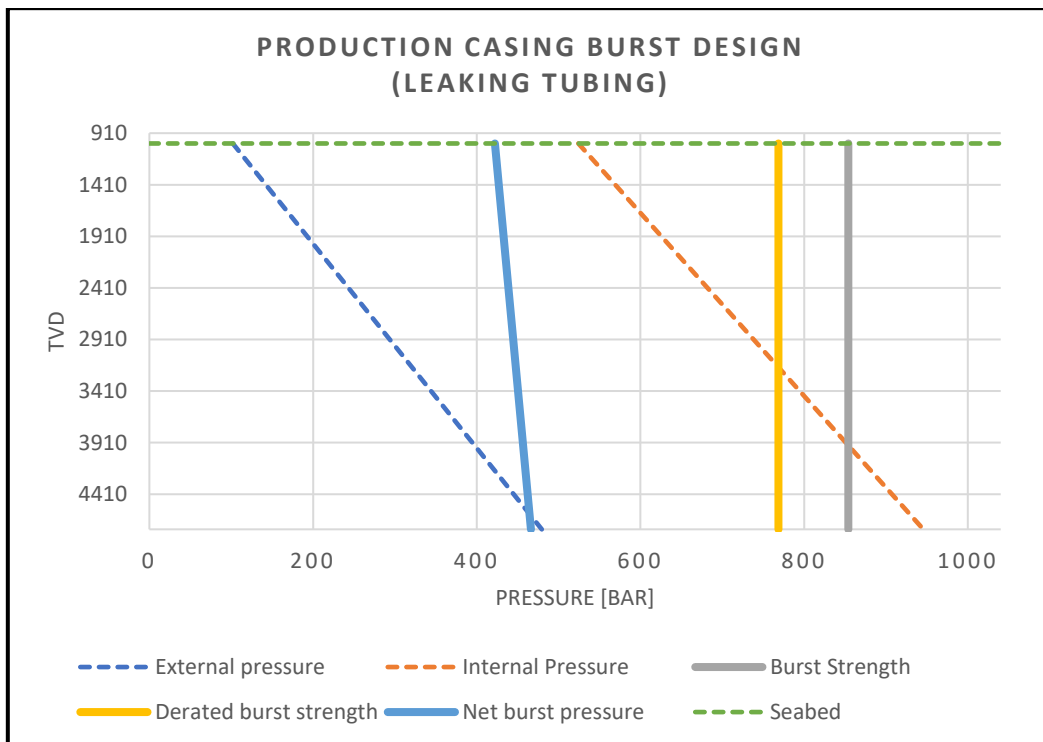*Figure 42: Well X-2: Production casing burst design – Formation fluid filled casing.*

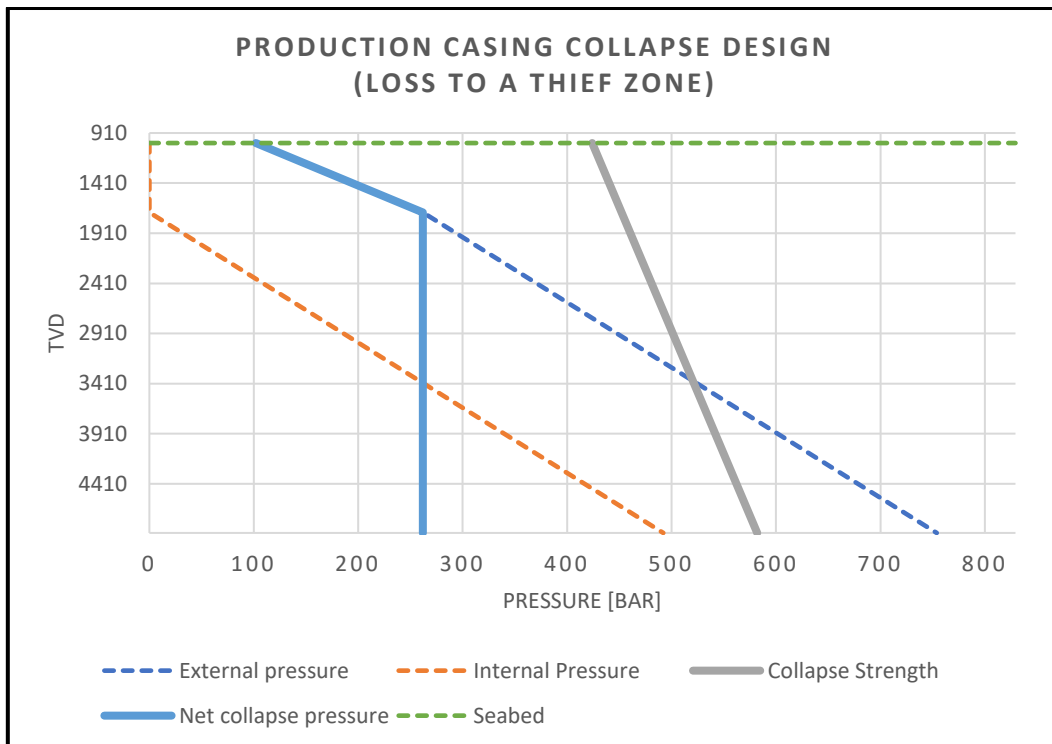*Figure 43: Well X-2: Production casing burst design – Leaking tubing.*

Figure 44: Well X-2: Production casing collapse design – Loss to a thief zone.

6.5.5 Discussion and optimization

The program works as expected and an evaluation of these results will therefore be conducted.

Surface casing:

The design factors that is returned from the program are within the limit requirements of the operator with a significant safety margin especially for the collapse and tension calculations.

The program reports reduced well integrity which means that if this well was t be filled with formation fluid and shit in, the shoe would not withstand the pressure.

Kick margin returns a value of 106,1 m^3 which is a very acceptable margin.

Weak point is reported to be in the shoe which is where it is desired to be.

Intermediate liner:

Design factors are satisfactory.

Program reports this liner to have full well integrity.

Intermediate casing:

Design factors are satisfactory.

Program reports this casing to have full well integrity.

<u>Production casing:</u>

Design factors are satisfactory.

Program reports the production casing to have full well integrity.

7 Discussion and Conclusion

The working stress design has been in use in the oil and gas industry for years and is still the go-to method for the design of casing strings. There are several reasons for this, but its simplicity is in no doubt a governing factor for why it still is. There exists a variety of programs that aims to provide users with satisfactory tools for calculating loads in a well, one of which is Stresscheck. This is an advanced program with countless parameters to consider and numbers to insert, but with an interface which is not as intuitive as one could hope for.

The Casing Design Optimization program created here proves to be a useful tool in the partial design and evaluation of a well. It is made as simple as possible in order to provide the user with a straightforwardly approach to casing design. The foundation for the program is the casing design chapter in "Modern Well Design" but along the way several modifications has been implemented to make the program more dynamic to every change that is made by the user. One of the main objectives from the start has been to limit the need for the user to interact with the program in order to achieve the results wanted. As it is now, hundreds of background calculations are conducted for every change made by the user, without the user being exposed to said calculations.

After the well parameters has been inserted into the only page that will accept data to be entered, the user can simply jump straight to the results page and get an instant look at the reported results. The first results the user is presented with is an overview of all relevant casing specific results connected to each string, such as design factors and if these factors are in accordance with the inserted operator safety factors, if the well has full or reduced well integrity, where the weak point in the well is located, and a calculated Kick margin for each given string. Directly below the casing specific results is a table of calculated minimum strength requirements are presented, based on the inserted casing setting depths. This makes it convenient for the user to quickly identify the needed strength of whichever casing has failed the design. Lastly the program presents a set of automatically adjusted plots directly beneath the tables of results, one plot for each criterion evaluated under each casing string, so that if a flaw is detected in a string the exact depth of this occurrence can be instantaneously identified.

The first case study was on a well in the Norwegian Sea, where the program reported some flaws in the design of some of the casing strings. This was improved by using the minimum requirement table to identify the needed strengths and then proceed to the casing data table to locate suitable casings. The data for this casing was inserted and it was observed that the casing now passed the requirements. This was the same approach for all the shortcomings reported in the design.

During the second case study on a well north of Africa in the Mediterranean Sea, some minor limitations to the program was observed, primarily that this well contained a liner

connected to the surface casing which is not a scenario that the program is designed for. In addition to this there are some minor adjustment problems with regard to the well fluid loss to a thief zone scenario for the liners, should the calculated mud equilibrium level end up being above the liner.

It must be stated that the mentioned flaws in the design not necessarily was deemed to be shortcomings from the operator's point of view, due to every operator working under a different set of internal rules and criteria.

Further work on this program should be to increase the options for design criteria on the various strings and provide the user with an option for which criteria the specific casing should be subjected to. One such criteria should be a halfway filled casing with formation fluid. The completely filled criterion used in the calculations in this program is considered very conservative and the user should have the option of using another. As already addressed, calculations for a liner connected to the surface casing should also be added. As the last point of improvement, there should exist an option to induce temperature derating effects on the deeper casing. As it is now there is no such option.

8 References

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A. Appendix

A.2. VBA code for axis adjustments

```vba
Function setChartAxis(sheetName As String, chartName As String, MinOrMax As String, _
    ValueOrCategory As String, PrimaryOrSecondary As String, Value As Variant)

'Create variables
Dim cht As Chart
Dim valueAsText As String

'Set the chart to be controlled by the function
Set cht = Application.Caller.Parent.Parent.Sheets(sheetName) _
    .ChartObjects(chartName).Chart

'Set Value of Primary axis
If (ValueOrCategory = "Value" Or ValueOrCategory = "Y") _
    And PrimaryOrSecondary = "Primary" Then

    With cht.Axes(xlValue, xlPrimary)
        If IsNumeric(Value) = True Then
            If MinOrMax = "Max" Then .MaximumScale = Value
            If MinOrMax = "Min" Then .MinimumScale = Value
        Else
            If MinOrMax = "Max" Then .MaximumScaleIsAuto = True
            If MinOrMax = "Min" Then .MinimumScaleIsAuto = True
    End If
    End With
End If

'Set Category of Primary axis
If (ValueOrCategory = "Category" Or ValueOrCategory = "X") _
    And PrimaryOrSecondary = "Primary" Then

    With cht.Axes(xlCategory, xlPrimary)
        If IsNumeric(Value) = True Then
            If MinOrMax = "Max" Then .MaximumScale = Value
            If MinOrMax = "Min" Then .MinimumScale = Value
        Else
            If MinOrMax = "Max" Then .MaximumScaleIsAuto = True
            If MinOrMax = "Min" Then .MinimumScaleIsAuto = True
    End If
```

```vba
      End With
End If

'Set value of secondary axis
If (ValueOrCategory = "Value" Or ValueOrCategory = "Y") _
    And PrimaryOrSecondary = "Secondary" Then

    With cht.Axes(xlValue, xlSecondary)
        If IsNumeric(Value) = True Then
            If MinOrMax = "Max" Then .MaximumScale = Value
            If MinOrMax = "Min" Then .MinimumScale = Value
        Else
            If MinOrMax = "Max" Then .MaximumScaleIsAuto = True
            If MinOrMax = "Min" Then .MinimumScaleIsAuto = True
        End If
    End With
End If

'Set category of secondary axis
If (ValueOrCategory = "Category" Or ValueOrCategory = "X") _
    And PrimaryOrSecondary = "Secondary" Then
    With cht.Axes(xlCategory, xlSecondary)
        If IsNumeric(Value) = True Then
            If MinOrMax = "Max" Then .MaximumScale = Value
            If MinOrMax = "Min" Then .MinimumScale = Value
        Else
            If MinOrMax = "Max" Then .MaximumScaleIsAuto = True
            If MinOrMax = "Min" Then .MinimumScaleIsAuto = True
        End If
    End With
End If

'If is text always display "Auto"
If IsNumeric(Value) Then valueAsText = Value Else valueAsText = "Auto"

'Output a text string to indicate the value
setChartAxis = ValueOrCategory & " " & PrimaryOrSecondary & " " _
    & MinOrMax & ": " & valueAsText

End Function
```