بسم الله الرحمن الرحيم

Sudan University of Science and Technology

college of petroleum Engineering and Technology

department of petroleum Engineering

Re-design Intermediate CasingTo Solve Corrosion Problem In Well In Higleeg – Case Study

إعادة تصميم عمود البطانة الأوسط لحل مشكلة التآكل في بئر بحقل هجليج دراسة حاله

Graduation project submitted to college of petroleum Engineering and Technology in Sudan University of Science and Technology
Partial fulfillment for one of requirements to take the degree of B.S.C in petroleum engineering

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Septemper-2014

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Date: / 9 /2014

الإستهلال

قال تعالى:((اللَّه ُنُورُ السَّمَاوَاتِ وَالأَرْضِ مَثَلُ نُورِهِ كَمِشْكَاةٍ فِيهَا مِصْبَاح الْمِصْبَاحُ فِي زُجَاجَةٍ الزُّجَاجَةُ كَأَنَّهَا كَوْكَبٌ دُرِّيٌّ يُوقَدُ مِن شَجَرَةٍ مُّبَارَكَةٍ زَيْتُونَةٍ لا شَرْقِيَّةٍ وَلا غَرْبِيَّةٍ يَكَادُ زَيْتُهَا يُضِيءُ وَلَوْ لَمْ تَمْسَسْهُ نَارٌ نُّورٌ عَلَى نُورٍ يَهْدِي اللَّهُ لِنُورِهِ مَن يَشَاء وَيَضْرِبُ اللَّهُ الأَمْثَالَ لِلنَّاسِ وَاللَّهُ بِكُلِّ شَيْءٍ عَلِيمٌ)).

سورةالنور........الآية (35).

الإهداء

نهدي هذا المشروع الي

امهاتنا؟

اللائي علمننا التحمل

ابائنا؟

الذين علمونا التحدي

اخواننا واخواتنا؟

الذين دعمونا في حياتنا وحفذونا

اساتذتنا؟

الذين علمونا القراءه والكتابة

واخيرآ ......

الى كليتنا الحبيبه التي تعلمنا منها دروس الحياه

الشكر التقدير

الشكر مقدم الى الله عز وجل اولآ واخرآ

نشكر كل من ساهم معنا وسره انجاز هذا البحث

والشكر موصول الى اساتذة كلية هندسة وتكنولوجيا النفط

و الشكر الجزيل الى استاذنا العزيز

د: محمد أحمد محمد نعيم

ABSTRACT

The well casing conceder one of the most important process during drilling and production so that must be designed carefully; there are many problems face the casing, one of this problems is leakage pressure such as that occur in many wells in higleeg oil field in Sudan; In this project a case study has been made in an example of well in higleeg oil field. Where the corrosion occurred in the intermediate casing at depth of (4m) below surface. The old design which set before completion was investigated to know if the problem caused by fail in design or not by using the graphical method; after design calculation revealed that the casing which must be run is J-55 with nominal weight 36 Ibm/ft from depth 0 – 1040m and H-40 with nominal weight 36 Ibm/ft from depth 1040 – 1660m and H-40 with nominal weight 32.3 Ibm/ft from depth 1660 – 2156m; however the casing string which set befor completion was N-80 with nominal weight 47 Ibm/ft this casing is good; so that the fail cannot occur by design; after that recommend to solve the problem by design casing patch to the intermediate casing with 8 ¼ in outside diameter and 4 meter length.

التجريد

تعتبر انابيب تبطين الآبار النفطية من أهم مقومات البئر أثناء الحفر والانتاج والحقن لذلك يجب تصميمها جيداً; وهنالك مشاكل كثيرة تواجه أنابيب البطانة أثناء تواجدها في البئر منها مشكلة ضياع الضغط مثل ما حدث في آبار عديدة في حقل هجليج النفطي في السودان. ويتناول هذا المشروع مشكلة بئر في حقل هجليج حيث حدث تآكل في أنبوب البطانة الأوسط في عمق 4 متر تحت سطح الأرض. فتم دراسة ظروف البئر وإعادة تصميم لانابيب البطانة الكاملة للبئر. وتم التحقق من التصميم القديم المدرج في البئر قبل الإكمال لمعرفة ما إذا كان المشكلة بسبب فشل في التصميم أم لا وذلك باستخدام الطريقة البيانية، وبعد إجراء حسابات التصميم وجد أن الأنبوب المفترض أن يدخل في البئر هو عمود مركب من J-55 36 Ibm/ft من عمق0m- 1040 و H-40 36 Ibm/ft من عمق 1660-1040m و H-40 32.2Ibm/ft من عمق 2156-1660m حسب مواصفات API والعمود المدرج في البئر قبل الإكمال كان N-80 47Ibm/ft وهو اجود من الانبيب المقترحة ولذلك استبعد أن يكون الفشل بسبب التصميم.وبعد ذلك تمت التوصية بمعالجة المشكلة بتصميم رقعة لأنبوب البطانة الأوسط بقطر ¼ 8 بوصة وطول 4 متر .

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Table Of Abbreviations:

Abbreviation	Meaning	
TD	Total depth	psi
G	Gas gradient	Psi/ft
P	Hydrostatic pressure	psi
C	Collapse pressure	psi
C_1	Collapse pressure at surface	psi
C_2	Collapse pressure at shoe	psi
B	Burst pressure	psi
B_1	Burst pressure at surface	psi
B_2	Burst pressure at total depth	psi
CSD	Casing shoe depth	ft
P_e	External pressure	psi
P_i	Internal pressure	psi
P_{form}	Formation pressure	psi
S_f	Safety factor	
W_n	Nominal weight	Ib/ft
B_f	Bouncy factor	
ρ	Mud density	PPg
L	Casing length	ft
T	Tension load	Ib

Chapter 1

Introduction

1.1. Introduction:

Despite efforts by Oil & Gas Operating Companies to design and install production tubing and casing strings that will remain leak-free for the operational life of their wells, there are a number of time depended degradation mechanisms that may result in leakage into the production tubing-by-production casing annulus. The most significant (or certainly the most publicized) of these degradation mechanisms appears to be corrosion and/or environmentally induced cracking of the tubing and casing strings and their associated completion hardware. The inner surface of the production tubing string is, of course, susceptible to the corrosive effects of the produced well fluids. The most significant active corrosive species found in the primary production from Gulf of Mexico (GOM) oil and/or gas wells appears to be the acid gases, carbon dioxide and hydrogen sulfide. When these acid gases dissolve in the formation brine or condensed water that is usually produced from the well, low pH, aqueous solutions result. These solutions, in turn, may produce corrosion and/or environmentally induced cracking (sulfide stress cracking or chloride stress cracking) of the alloys used in the production tubing and production casing strings.

There appears to be a growing body of recent evidence that traces of organic acids (sometimes present in produced well fluids) may also play a significant role in lowering the pH, and thus increasing the corrosivity, of the produced water or brine. Also, in gas lift wells and water injection wells (used for reservoir pressure maintenance),oxygen can be accidentally introduced into the well tubing or into the tubing-by-production casing annulus. At comparable concentrations, it is known that oxygen is much more corrosive than either CO2 or H2S to carbon and low alloy steels. Experience has thus shown that even very small concentrations of oxygen in hot salt water can result in very high corrosion and pitting rates in carbon and low alloy steels. The exterior of the production casing string (below the outer, surface and/or intermediate strings) may also be exposed to the action of corrosive formation fluids. The extent that the formation fluids attack the exterior of the production casing will, of course, depend upon the quality and the height of the cement used to install the production casing.

In addition the “exposed” exterior of the production casing string may suffer corrosion due to the action of any “stray DC currents” that may “go to ground” over this section of casing. The outer surface of the production tubing and the inner surface of the production casing may also suffer corrosive attack by the “packer” or well completion fluids that are usually left in the annulus for well control purposes. These completion fluids are commonly high salinity brines that may become very aggressive if they are contaminated by small leaks of carbon dioxide or hydrogen sulfide (from the production stream) or by small concentrations of dissolved oxygen (air).

1.2. Problem statement:

The casing has many important functions such as isolate the formation; protect weak formations from the high mud weights and To seal off lost circulation zones and other functions; but there are many problems occur to the casing, one of this problems is corrosion which conceder from the biggest problems which face the casing. It cause lost circulation during drilling and difficult to production from the well; this problem face many wells in higleeg oil field in Sudan. This project study this problem and recommend the suitable solution for x well which did not study before.

1.3. The Objectives:

1- Investigate from old design.

2- Solve the corrosion problem in intermediate casing.

Chapter 2

Theoretical background and literature review

2.1. Introduction to the Casing Design Process:

It is generally not possible to drill a well through all of the formations from surface (or the seabed) to the target depth in one hole section. The well is therefore drilled in sections, with each section of the well being sealed off by lining the inside of the borehole with steel pipe, known as casing and filling the annular space between this casing string and the borehole with cement, before drilling the subsequent hole section. This casing string is made up of joints of pipe, of approximately 40ft in length, with threaded connections. Depending on the conditions encountered, 3 or 4 casing strings may be required to reach the target depth. The cost of the casing can therefore constitute 20-30% of the total cost of the well (£1-3m). Great care must therefore be taken when designing a casing program which will meet the requirements of the well.

The casing design process involves three distinct operations: the selection of the casing sizes and setting depths; the definition of the operational scenarios which will result in burst, collapse and axial loads being applied to the casing; and finally the calculation of the magnitude of these loads and selection of an appropriate weight and grade of casing.

2.2. Casing Functions:

• To prevent unstable formations from caving in.

• To protect weak formations from the high mud weights that may be required in subsequent hole sections. These high mud weights may fracture the weaker zones.

• To isolate zones with abnormally high pore pressure from deeper zones this may be normally pressured.

• To seal off lost circulation zones.

• When set across the production interval: to allow selective access for production / injection/control the flow of fluids from, or into, the reservoir(s).

2.3. The type of casing:

2.3.1. Conductor Casing:

The conductor is the first casing string to be run, and consequently has the largest diameter. It is generally set at approximately 100ft below the ground level or seabed. Its function is to seal off unconsolidated formations at shallow depths which, with continuous mud circulation, would be washed away. The surface formations may also have low fracture strengths which could easily be exceeded by the hydrostatic Pressure exerted by the drilling fluid when drilling a deeper section of the hole.

In areas where the surface formations are stronger and less likely to be eroded the conductor pipe may not be necessary. Where conditions are favorable the conductor may be driven into the formation and in this case the conductor is referred to as a stove pipe.

2.3.2. Surface Casing:

The surface casing is run after the conductor and is generally set at approximately (1000 - 1500 Ft.) below the ground level or the seabed. The main functions of surface casing are to seal off any fresh water sands, and support the wellhead and BOP equipment. The setting depth of this casing string is important in an area where abnormally high pressures are expected. If the casing is set too high, the formations below the casing may not have sufficient strength to allow the well to be shut-in and killed if a gas influx occurs when drilling the next hole section. This can result in the formations around the casing crate ring and the influx flowing to surface around the outside of the casing.

2.3.3. Intermediate Casing:

Intermediate (or protection) casing strings are used to isolate troublesome formations between the surface casing setting depth and the production casing setting depth. The types of problems encountered in this interval include: unstable shale, lost circulation zones, abnormally pressured zones and squeezing salts. The number of intermediate casing strings will depend on the number of such problems encountered.

2.3.4. Production Casing:

The production casing is either run through the pay zone, or set just above the pay zone (for an open hole completion or prior to running a liner). The main purpose of this casing is to isolate the production interval from other formations (e.g. water bearing sands) and/or act as a conduit for the production tubing. Since it forms the conduit for the well completion, it should be thoroughly pressure tested before running the completion.

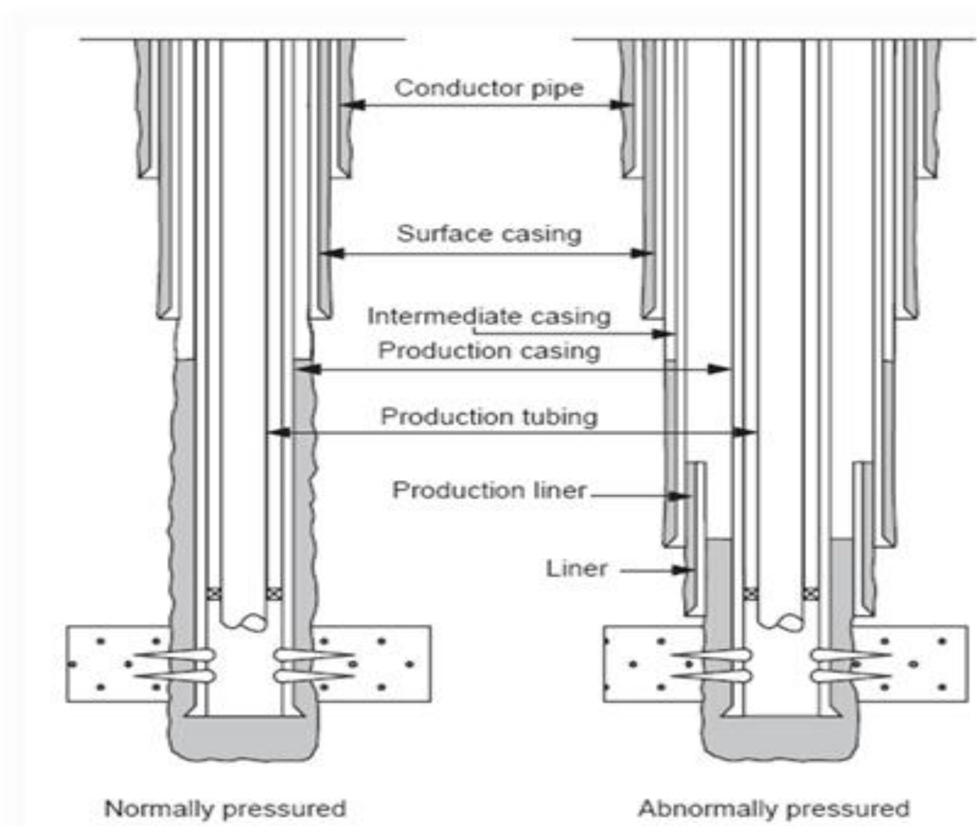

Fig.(1.1). The type of casing

2.4. Properties Of Casing:

2.4.1. Casing Size:

Outside diameter (O.D).

2.4.2. Length of Joint:

The length of a joint of casing has been standardized and classified by the API .

2.4.3. Casing Weight:

For each casing size there are a range of casing weights available. The weight of the casing is in fact the weight per foot of the casing and is a representation of the wall thickness of the pipe.

2.4.4. Casing Grade:

The chemical composition of casing varies widely, and a variety of compositions and treatment processes are used during the manufacturing process This means that the physical properties of the steel varies widely. The materials which result from the manufacturing process have been classified by the API into a series of “grades” (Table 3). Each grade is designated by a letter, and a number. The letter refers to the chemical composition of the material and the number refers to the minimum yield strength of the material e.g. N-80 casing has a minimum yield strength of 80000 psi and K-55 has a minimum yield strength of 55000 psi. Hence the grade of the casing provides an indication of the strength of the casing. The higher the grade, the higher the strength of the casing.

In addition to the API grades, certain manufacturers produce their own grades of material. Both seamless and welded tubular are used as casing although seamless casing is the most common type of casing and only H and J grades are welded.

Table.(1.3).Casing grades and properties

API GRADES			NON-API GRADES		
	Minimum Strength psi			Minimum strength psi	
Grade	Yield	Ultimate	Grade	Yield	Ultimate
H-40	40,000	60,000	S80	55,000	95,000
J-55	55,000	75,000	S0090	90,000	105,000
K-55	55,000	95,000	SS95	80,000	100,000
C-75	75,000	95,000	S95	95,000	110,000
N-80	80,000	100,000	S105	95,000	110,000
C-95	95,000	105,000	S00125	125,000	135,000
P-110	110,000	125,000	S00140	140,000	150,000
	_	_	V150	150,000	160,000
	_	_	S00155	155,000	165,000

2.4.5. Connections:

Individual joints of casing are connected together by a threaded connection. These connections are variously classified as: API; premium; gastight; and metal-to metal seal. In the case of API connections, the casing joints are threaded externally at either end and each joint is connected to the next joint by a coupling which is threaded internally (Figure 5). A coupling is already installed on one end of each joint when the casing is delivered to the rig. The connection must be leak proof but can have a higher or lower physical strength than the main body of the casing joint.

Wide varieties of threaded connections are available. The standard types of API threaded and coupled connections are:

• Short thread connection (STC)

• Long thread connection (LTC)

• Buttress threads connection (BTC

2.5. Casing patch:

Casing PatchDesigned to seal perforations, collar and thread leaks, splits and limitedcorroded areas in tubing and casing and to provide added protectionduring squeeze jobs, the HOMCO internal steel liner casing patch isas versatile as it is effective to any depth.The HOMCO patch has repeatedly sealed leaks and perforations wherecementing efforts have failed, including in production wells, wells thatmust be deepened after patching and disposal storage wells. The patchis permanent yet can be removed from the wellbore by milling.

2.5.1. Advantages:

The HOMCOpatch offers significant advantages over other sealing methods.

Repairs are made quickly. Total setting time is limited only by roundtrip time.Operations can be resumed as soon as the setting tool is pulled and the patch is pressure tested.

2.5.2. Procedure:

1. DE pressures the cavern by removing all product that can feasibly be removed. Describe the procedure for removing product from the cavern, including any product trapped behind the casing.

2. Fill the cavern with brine.

3. Remove all tubing string(s) from the well.

4. Conduct a casing evaluation to determine the condition of the entire casing string. The operator should determine the following:

a. The type of leak

b. The internal diameter of the casing to determine if it is oversized

c. The position of the hold down.

d. The location of the leak.

5. Additionally, a gamma ray log shall be run to correlate the depth of the leak and the patch position.

6. Initiate any hole preparations and procedures required for the type of leak identified and approved for repair.

7. Run a casing scraper to clean the casing in the patch area.

8. Make a gage or drift run to identify any restrictions in the casing. Describe tentative procedures for removing any restrictions.

9. Run a casing caliper log if the internal diameter of the casing is not known or is questionable. Determine the amount of reduction to the inside diameter of the casing after the patch is applied.

10. Determine the pressure requirements for the patch and confirm that the patch is designed for the size and weight of the casing. Refer to any charts provided by the patch manufacturer.

11. Follow manufacturer's recommended safety precautions while running the patch.

12. When setting the patch, overlap the leak by 6 to 8 feet on each end. When patching corroded casing, cover the full joint of casing with a 6 to 8 foot overlap at each end.

13. Pressure test the patch. Allow the patch to set at least 24 hours before testing. Do not exceed differential pressure ratings provided by the manufacturer.

14. Submit a casing repair report, including description of field work

2.6. Casing Corrosion:

2.6.1. CO2 Corrosion:

The severity of corrosion due to carbon dioxide in "sweet" oil and gas wells depends upon a number of environmental conditions. These include (but are not limited to): the partial pressure of carbon dioxide in the produced gas, the well temperature, the composition of the produced water, the amount and characteristics of any liquid hydrocarbons produced from the well, the velocity and flow regime of the production stream, the in-situ or down-hole pH of the produced water and the tendency for stable iron carbonate scale to form on the corroded tubing surface. Corrosion due to carbon dioxide can occur as general weight-loss corrosion, as pitting and as localizedcorrosion in areas of turbulence and changes in flow direction. Pieces of equipment in the production tubing string that contain changes or restrictions in the flow path are thus particularly susceptible to corrosion attack. For example, accelerated attack has been observed in landing nipples, in elbows at the wellhead, and in the “J-areas” ofAPI connections.

Numerous models that purport to predict the rate of corrosion due to carbon dioxide have been described in the literature. These models are based both on considerations of basic electrochemical and hydrodynamic effects and upon expert systems developed from field observations. Several of the domestic model developers also offer commercially available technical support to operators that may need to investigate the anticipated severity of corrosion for specific applications. Valdes et al March.(1998)

In using the corrosion rates predicted by a model (for assessing the anticipated life of a tubing string or in performing economic evaluations of alternative corrosion mitigation schemes), it is important to determine the extent to which the model incorporates all the important aspects of the specific well under consideration. Nyberg et al.(1998) It should also be remembered that the conditions in the well (e.g., total well pressure and thus partial pressure of carbon dioxide, composition of the produced brine, concentration of hydrogen sulfide, flow rate and flow regime of the produced well stream, etc.) may undergo substantial changes during the life of the well. The predicted corrosion rates over the total anticipated range of operating conditions that may be experienced during the life of the well should thus be investigated.

Before using a particular model, the user should also understand the basic philosophy used in developing the model. It is our understanding that some of the models are intended to give conservative, worst case corrosion predictions while other models reportedly use correlations with field data to produce more realistic, representative predictions.Crolet et al.(1999)

2.6.2. H2S Sulfide Stress Cracking:

Tubing and casing strings are typically “designed” for resistance to sulfide stress cracking (SSC) by limiting the selection of materials for sour service to those that are essentially immune to SSC (regardless of exposure time) at stress levels up to some useful percentage of their yield strengths. The concentrations of hydrogen sulfide above which the production stream is considered “sour” (and which will thus probably cause SSC) are defined “Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment”. Other important variables that have an effect upon the tendency for alloys to exhibit SSC include:

1. Alloy hardness,
2. Alloy chemistry and heat treatment,
3. Water/brine pH,
4. Temperature,
5. Time,
6. Total stress.

Other variables may also have an effect upon the tendency of an alloy to exhibit SSC. These include:

1. Water/brine composition (salinity and buffering capacity),
2. Presence/absence of cold work in the alloy,
3. Presence/absence of elemental sulfur in the well environment,
4. The manufacturing process used to produce the alloy.

Alloys were originally added to MR0175 based upon their successful use in sour service in the field. MR0175 has, however, since been accepted as a mandatory requirement by several regulatory bodies. New alloys are thus presently added to MR0175 based upon the results of laboratory testing. The testing procedures given in NACE Standard Test Method, TM0177, “Laboratory Testing of Metals for Resistance to Specific Forms of Environmental Cracking in H2S Environments”, are typically used as the vehicle to add new materials to MR0175.Kermani et al .(1991)

Materials that have been found to be acceptable (from the standpoint of SSC) for specific equipment and components used in oil & gas production are discussed in Sections 6 through 11 of MR0175. Section 10, in particular, discusses tubular and subsurface equipment for use in oil & gas production.

2.6.3. Other Damage:

In addition to CO2 corrosion and sulfide stress cracking, other time dependent damage mechanisms thatmay lead to leakage into the “primary”, production tubing-by-production casing, annulus include the following:

1. Erosion,

2. Galvanic corrosion effects caused (for example) by coupling more corrosion resistant alloy completion hardware (e.g., packers, etc.) to carbon steel tubular,

3. Environmentally and/or stress induced degradation of elastomeric seals,

4. Wear/abrasion of “movable” seal areas due to accumulation of debris and/or corrosion products,

5. High or low cycle metal fatigue due to temperature and/or pressure cycles,

6. Gradual penetration of the thread dope used to seal API connections by the combined effects of temperature/pressure cycles and attack of the thread dope by high pressure gas,

7. Crevice corrosion in tubing or casing connections, seal areas, etc.,

8. Corrosion initiated by improperly executed acidizing operations,

9. Corrosion caused by contamination of the well by oxygen (accidental introduction of air into the well),

10. Corrosion in the well annulus due to the action of bacteria and/or algae (MIC),

11. Damage caused by running wire lines and/or coiled tubing in the well.

2.6.4. Corrosion prevention:

Methods that have commonly been used to successfully combat corrosion (and cracking) of production casing, tubing and completion hardware include:

• Selection and Use of High Alloy Tubular (as discussed above),

• Use of Corrosion Inhibitors,

• Use of Internal Plastic Coatings.

The use of production operation changes (such as reduction of the production rate of high temperature, high pressure gas wells) that might also reduce the corrosion and erosion rates in the well are outside the scope of this presentation.

(1) Corrosion Inhibitors:

Discussions of corrosion inhibitors and their use in production applications are available in several sources. The inhibitors typically used for down-hole applications consist of high molecular weight, polar, organic molecules. The active portion of the inhibitor molecule generally consists of or contains a monoamine, ad amine or an amide. The inhibitor apparently functions when the active end of the inhibitor molecule forms a weak “bond” to the metal surface. The organic end of the inhibitor molecule then forms an oily, water repellant film over the protected surface.

The amount of inhibitor attached to the surface (and thus the level of corrosion protection) apparently depends primarily upon the concentration of inhibitor in the produced fluids as well as the temperature. There are also temperature limits above which the inhibitors change composition and thus lose most of their effectiveness.

Comparative testing of various candidate inhibitors in test environments similar to those anticipated in the field should be considered prior to initiating an inhibition program. Consideration should also be given to closely monitoring the on-going performance of inhibitors after the start of production operations.

Methods of inhibitor application include both continuous and intermittent (or batch) treatments. The method of application usually depends upon the well configuration. In continuous inhibitor injection, a chemical displacement pump at the surface may be used, in conjunction with small diameter concentric or non-concentric tubing strings, to pump inhibitor to the bottom of the well on a more-or-less continuous basis. The use of a concentric string may not require that the well be completed with a packer between the production tubing and the production casing. A non-concentric inhibitor injection string, on the other hand, can be used to introduce the inhibitor below a packer or through a side pocket mandrel. Intermittent or batch inhibitor treatments can be done in wells that have been completed with or without a bottom-hole packer. For wells completed without a packer, a common treatment procedure consists of injecting a “batch” of inhibitor into the production tubing-by-production casing annulus and then by-passing production from the well into the annulus. The inhibitor batch may be simply displaced into the bottom of the tubing from the annulus and then produced with the well fluids/gas after one pass through the tubing. Alternatively, the produced inhibitor batch may subsequently be circulated back into the annulus (for re-circulation again at a later date). For wells with a packer, the "tubing displacement" technique is often used. In this method, an appropriately diluted batch of inhibitor is displaced to the bottom of the tubing string. After what is judged an appropriate shut-in period, the well is put back into normal operation, thus coating the inner surface of the production tubing with inhibitor as the inhibitor is produced from the well. For areas where experience has shown that the inhibitor will not "damage" (significantly reduce the production capacity of) the producing formation, an inhibitor "squeeze" technique might be considered in wells that are completed with a packer. In this method, the inhibitor "batch" is displaced to the bottom of the well and is then displaced or "squeezed" into the surrounding producing formation. The inhibitor is thus adsorbed onto the internal surfaces of the formation and is slowly produced back up the production tubing when the well is put back into normaloperation. In wells with a packer, a down-hole injector valve can also be used to periodically or continuously inject inhibitor solution into the production tubing. In this method, the annulus is typically kept full of inhibitor solution. The inhibitor treatment then consists of displacing inhibitor into the tubing by injecting additional inhibitor into the annulus at the surface. Despite the application technique employed, it is recommended that candidate corrosion inhibitors be subjected to comparative testing prior to final selection for use in a well. This testing might simply consist of static exposures of steel coupons to simulated produced brines to which inhibitors have been added. Slightly more sophisticated testing might include "wheel" testing in which coupons are mounted on a wheel that is rotated suchthat the coupons spend part of their exposure submerged in the brine and part of their exposure in the gas phase of the simulated production environment. Finally, a re-circulating flow loop (in which the anticipated down-hole flow conditions of the well are duplicated as closely as possible) could be used to give even more realistic predictions of inhibitor performance.

(2) Plastic Coatings:

Discussions of plastic coatings for use in production tubing are available. These sources indicate that the coating systems normally used to internally coat production tubing consist of either phenolic or fusion bonded epoxies. Information concerning plastic coating systems from two of the major suppliers of these systems is given in Attachment D. A review of the information in Attachment D reveals that the upper temperature limit of the coating systems ranges from approximately 2000F to approximately 4000F, depending upon the coating. Thenformation also indicates, however, that the coating systems may exhibit substantially lower temperature limits when exposed to significant concentrations of H_2S. Adequate care must be exercised by the coating manufacturers during the application of internal plastic coatings. In particular, the inner surface of the tubing is usually given an initial cleaning by acid pickling and water washing. After the initial cleaning, the inner surface is then sandblasted in order to remove any surface oxidation or remaining solids. The coating should then be applied as soon as possible following the cleaning, before a fresh layer of rust can form on the cleaned surface. The coatings are then checked for pin-holes (or “holidays”) using an electrical detector that is sensitive to high conductivity paths through the coating. A NACE document, Standard RP0191, Standard Recommended Practice, “The Application of Internal Plastic Coatings for Oilfield Tubular Goods and Accessories”, discusses, in detail, the points mentioned above. Finally, it should be realized that internal coating systems are susceptible to mechanical damage due to flexing and/or mechanical impacts of the pipe during transportation and running of the tubing. The coatings near the ends of the pipe are particularly susceptible to handling and “stabbing” damage while the pipe is being run in the well.

2.6.5. Corrosion Monitoring:

What appears to be a more or less complete compilation of the possible techniques for monitoring corrosion in general industrial applications has recently been published by NACE in the NACE Publication 3T199, “Techniques for Monitoring Corrosion and Related Parameters in Field Applications”. In Publication 3T199,

the monitoring techniques are divided into the following categories:

• Direct methodsIntrusive & Non-intrusive,

• Indirect techniquesOn-line & Off-line.

Direct, intrusive monitoring methods include (for example): coupons, and electrical probes that are inserted through the wall (pressure boundary) of the equipment. Direct, non-intrusive methods, on the other hand, include measurement techniques that can be performed without penetrating the wall of the equipment. These techniquesinclude: ultrasonic, magnetic flux leakage, eddy current techniques, radiography and acoustic emission. Indirect, on-line techniques consist of measurements of some characteristic of the active corrosionenvironment. These include (for example): pH, solution conductivity, and dissolved oxygen content of the brine, as well as flow velocity, pressure and temperature of the produced fluids/gas. Indirect, off-line methods consist primarily of measurements of the corrosion environment that are made on samples that have been removed from the system under investigation. These indirect, off-line measurements include measurements of: alkalinity, metal ion concentrations (e.g., iron and manganese), dissolved solids, dissolved gases and residual inhibitor concentrations in the produced water/brine.

Our review of the literature revealed that the techniques that are most commonly used to successfully monitor on-going, active corrosion of down-hole tubular include: measurements of iron and manganese contents in the produced brines and measurements of residual inhibitor concentrations. Unfortunately, the areas of primary interest in the tubing strings may be remote from the surface and significant changes in the corrosion environment may thus occur as the production stream is brought to the surface. The direct, intrusive techniques and the remainder of the indirect techniques (other than the measurements of iron and manganese and residual inhibitor concentrations) have thus not proven to be very useful in tracking down-hole corrosion rates. Also, while dissolved iron and manganese concentrations and residual inhibitor concentrations can apparently be successfully correlated with over-all average corrosion rates in production tubing strings, these measurements cannot predict where the corrosion is taking place and whether or not it may be concentrated over some relatively small portion of the total well depth.

NACE publications describing the use of coupons, hydrogen probes, and galvanic probes for monitoring corrosion in oil and gas operations are available. There is also an

NACE publication that describes the use of "iron counts" (dissolved iron concentrations in the produced water) for monitoring down-hole corrosion processes. Fortunately, down-hole casing and tubing logging tools have been developed that use most of the measurement techniques described above as the "direct, non-intrusive techniques". Although the individual measurement techniques used in these tools may be described as "non-intrusive", for the well taken as a whole, thetools actually are intrusive since the well flow must be shut-in in order to allow the introduction of the logging tools into the top of the well.

Another NACE document is available that describes the logging tools that have been developed for evaluating down-hole corrosion in casing and tubing strings. The down-hole casing and tubing logging tools described in the NACE document include the following:

- Multi-finger, mechanical calipers,
- Ultrasonic tools,
- Electromagnetic tools
- DC flux leakage tools
- AC tools.

The NACE document also includes discussions of casing potential profile tools, temperature measuring tools and optical (TV camera) inspections. The measurements of these latter tools, however, do not depend upon the remaining wall thickness of the casing or tubing and their results are thus only indirect or qualitative indicators of the condition of the tubular at the time of the inspection.

2.7. Literature review:

(1) Scott Oliphant, Devon Canada, Well Casing Corrosion, 2000.

One of the first studies of external casing corrosion in Alberta was performed by Caswell in 1987 - 1988. The study was entitled "External Casing Corrosion Survey"B7B and was prepared for the NACE Calgary Section and a number of oil and gas producing companies.

The report was based on 525 casing inspection logs and 160 casing failure reports. The casing inspection logs were supplied by two logging companies and supplemental information was provided by the ERCB and the participating oil and gas companies. There were a number of main conclusions from the report:

1. The ratio of external corrosion to internal corrosion for the wells in the survey was 72.5 to 27.5. These results were consistent with the ratio of 70 / 30 suggested by NACE.

2. The fields with the most severe corrosion rates were Bonanza and Caroline – Westward Ho. Other fields with high corrosion rates, but a lower average age, were Rainbow Lake, Sylvan Lake, Mitsue,Kaybob South and Judy Creek. A list of the fields with the most severecorrosion rates.

3. The most active geological formations are limestone (CaCOB3B) formations. In the southern part of the province the most active formations are the Lea Park and the Colorado. The Banff and the Wabamun are the most aggressiveformations in the northern area of the province.

4. The majority of casing penetrations, 61%, occur in the top 1500 m of casing which is generally the open-hole area below the surface casing and above the cement top.

5. Most of the fields with severe external corrosion are located in central Alberta where some of the oldest wells are found. Exceptions to this are Rainbow Lake, Bonanza, Nipisi and Taber. Other geographical areas with moderate or severe areas of corrosion are those zones with folded formations along the Foothills.

6. Wells with strings of mixed casing grades (e.g. J-55 and N-80) show an increased tendency toward external corrosion. The casing grade N-80 is less susceptible to external corrosion than J-55.

7. The occurrence of holes in the production casing located inside the surface casing is strongly related to the presence of severe external corrosion in the remainder of the casing string.

The report concluded that external casing corrosion is responsible for 70% of the casing corrosion problems in Alberta. The main factors affecting the degree of corrosion are the age of the well, the formations penetrated by the well casing and the drilling and completion practices such as the casing grade, the type ofdrilling mud used and the type and amount of cement used.

(2) J. Kolts and S. W. Ciaraldi, “Corrosion Resistant Alloys for Oil and Gas Production, Volumes I & II”, NACE, 1996.Alloys were originally added to MR0175 based upon their successful use in sour service in the field. MR0175 has, however, since been accepted as a mandatory requirement by several regulatory bodies

Chapter 3

Methodology

There are three basic forces which the casing is subjected to: collapse, burst and tension. These are the actual forces that exist in the wellbore. They must first be calculated and must be maintained below the casing strength properties. In other words, the collapse pressure must be less than the collapse strength of the casing and so on.

Casing should initially be designed for collapse, burst and tension. Refinements to the selected grades and weights should only be attempted after the initial selection is made.

3.1. Collapse:

Collapse pressure originates from the column of mud used to drill the hole, and acts on the outside of the casing. Since the hydrostatic pressure of a column of mud increases with depth, collapse pressure is highest at the bottom and zero at the top, see Figure (3.1).

This is a simplified assumption and does not consider the effects of internal pressure.For practical purposes, collapse pressure should be calculated as follows:

Collapse pressure = External pressure – Internal pressure ……….,………… (3.1)

The actual calculations involved in evaluating collapse and burst pressures are usually straight forward. However, knowing which factors to use for calculating external and internal pressures is not easy and requires knowledge of current and future operations in the wellbore.Until recently; the following simplified procedure was used for collapse design:

(1) Casing is assumed empty due to lost circulation at casing setting depth (CSD) or at TD of next hole, see Figure (3.1).

(2) Internal pressure inside casing is zero.

(3) External pressure is caused by mud in which casing was run in.

(4) No cement outside casingHence using the above assumptions and applying Equation (3.1), only the external pressure need to be evaluated.

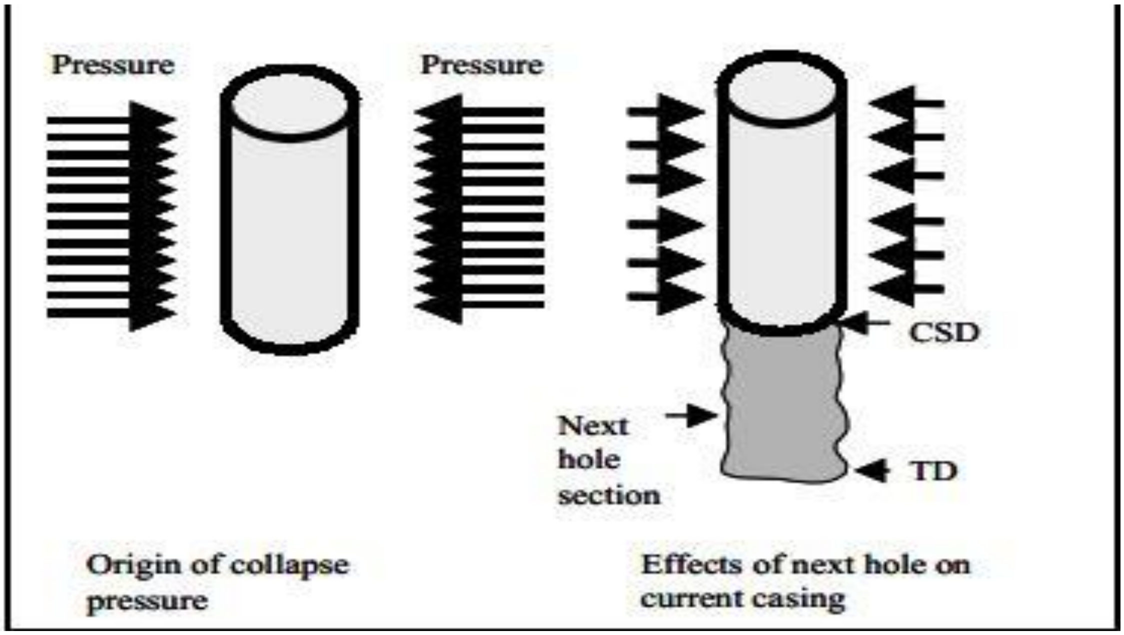

Fig.(3.1) collapse

Therefore:

Collapse pressure (C)= mud density x depth x acceleration due to gravity

$C = 0.052 \times \rho \times CSD$….psi (3.2)

Where: $\rho$is in ppg and CSD is in ft

The above assumptions are very severe and only occur in special cases. The following sections will provide details on practical situations that can be encountered in field operations.

3.2. Burst:

In oil well casings, burst occurs when the effective internal pressure inside the casing (internal pressure minus external pressure) exceeds the casing burst strength.Like collapse, the burst calculations are straightforward. The difficulty arises when one attempts to determine realistic values for internal and external pressures.In development wells, where pressures are well known the task is straight forward. In exploration wells, there are many problems when one attempts to estimate the actual formation pressure including:

• the exact depth of the zone (formation pressure increases with depth)

• type of fluid (oil or gas)

• porosity, permeability

•temperature

The above factors determine the severity of the kick in terms of pressure and ease of detection.Clearly, one must design exploration wells for a greater degree of uncertainty than development wells. Indeed, some operators manuals detail separate design methods for development and exploration wells. In this search, a general design method will be presented and guidelines for its application will be given.

3.2.1. Burst Calculations:

Burst Pressure, B is give by:

B = internal pressure – external pressure

(1) Internal Pressure:

Burst pressures occur when formation fluids enter the casing while drilling or producing next hole. Reference to Figure (3.2), shows that in most cases the maximum formation pressure will be encountered when reaching the TD of the next hole section.For the burst criterion, two cases can be designed for:

1. Unlimited kick

2. Limited kick

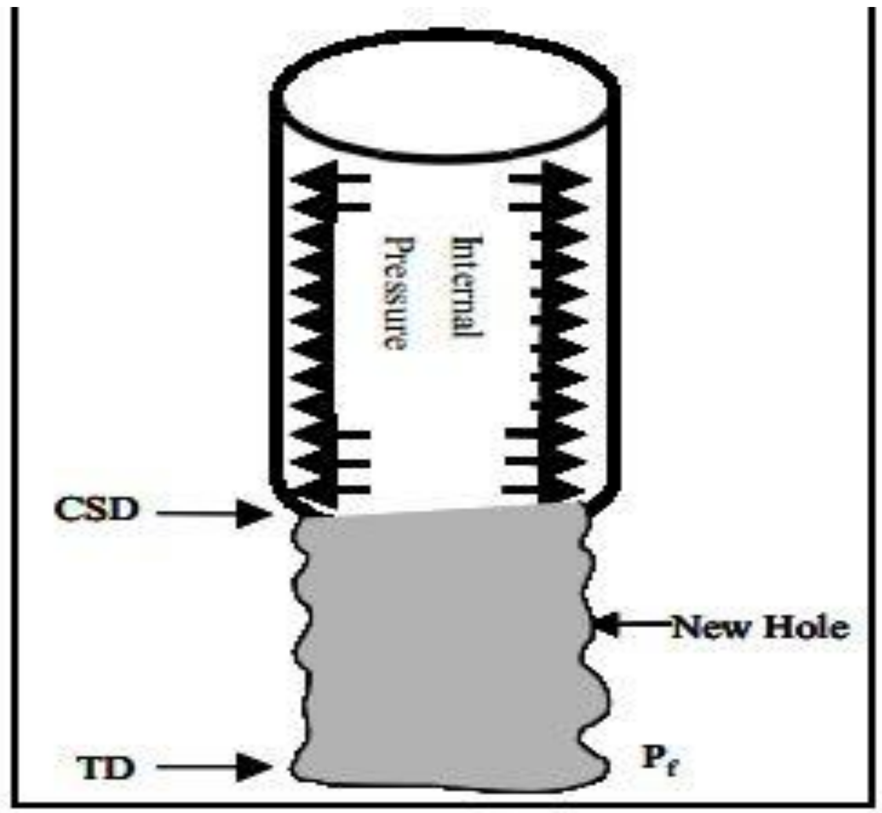

Fig.(3.2) Burst

(2) External Pressure For Burst Design:

The external pressure (or back-up load) is one of the most ambiguous variables to determine. It is largely determined by the type of casing being designed, mud type and cement density, height of cement column and formation pressures in the vicinity of the casing.In practice, although casings are cemented (partially or totally to surface), the external pressure is not based on the cement column. At first glance, this seems strange that we go into a great deal of effort and expense to cement casing and not use the cement as a back-up load. The main reasons for not using the cement column are:

1. it is impossible to ensure a continuous cement sheet around the casing

2. any mud trapped within the cement can subject the casing to the original hydrostatic pressure of the cement

3. the cement sheath is usually highly porous but with little permeability and when it is in contact with the formation, it can theoretically transmit the formation pressure to the casing

Because of the above, the exact degree of back-up provided by cement is difficult to determine. The following methods are used by a number of oil companies for calculating external pressure for burst calculations:

1. Regardless of whether the casing is cemented or not, the back-up load is provided by a column of salt saturated water. Hence the

external pressure = 0.465 psi/ft x CSD (ft) ………………………………… (3.3)

The above method is the simplest and is used by many people in the industry. It assumes all muds and cements behind casing degrade with time to a density equivalent to salt-saturated mud having a density of 0.465 psi/ft. In fact, this assumption is used by some commercial casing design software.The author suggests using this method for all casings likely to be in the ground for more than five years.

2. If casing is cemented along its entire length and the casing is in contact with a porous formation via a cement sheath, then with time the cement sheath will degrade and the casing will be subjected to the pore pressure of the open formation. Hence

External pressure = maximum expected pore pressure …………………….. (3.4)

In practice only conductor and shallow surface casings are cemented to surface. Hence the maximum pore pressure is likely to be that of a normally pressure zone of around 0.465 psi/ft.

3. for uncemented casings:

• In the open hole, use a column of mud to balance the lowest pore pressure in the open hole section

• inside another casing, use mud down to TOC and then from TOC to casing shoe use a column of mud to balance the lowest pore pressure in the open hole section

This scenario usually applies to intermediate and production casings. In fact, the author used the above to design high pressure/high temperature wells in the North Sea. Without this realistic assumption, casing of unnecessarily higher grade or weight would be required.

3.2.2. Burst Calculations For Individual Casing Strings:

At the top of the hole, the external pressure is zero and the internal pressure must be supported entirely by he casing body. Therefore, burst pressure is highest at the top and lowest at the casing shoe where internal pressures are resisted by the external pressureoriginating from fluids outside the casing. As will be shown later, in production casing the burst pressure at shoe can be higher than the burst pressure at surface in situations where the production tubing leaks gas into the casing.

(1) Conductor:

There is no burst design for conductors.

(2) Surface and Intermediate Casings:

For gas to surface (unlimited kick size), calculate burst pressures as follows:

Calculate the internal pressures (Pi) using the maximum formation pressure at next hole TD, assuming the hole is full of gas, (see Figure 3.2).

Burst at surface = Internal pressure (Pi) (Pf - G x TD)– external pressure

Burst pressure at surface (B1) = Pf - G x TD …………………………….. (3.5)

(note external pressure at surface is zero)

Burst pressure at casing shoe (B2) = internal pressure (Pf - G x (TD - CSD)- backup

load= Pi- 0.465 x CSD

B2 = Pf - G x (TD - CSD) - 0.465 x CSD ………………………………… (3.6)

The back-up load is assumed to be provided by mud which has deteriorated to salt-saturated water with a gradient of 0.465 psi/ft.

(3) Production Casing:

The worst case occurs when gas leaks from the top of the production tubing to the casing. The gas pressure will be transmitted through the packer fluid from the surface to the casing shoe (see Figure 3.3).

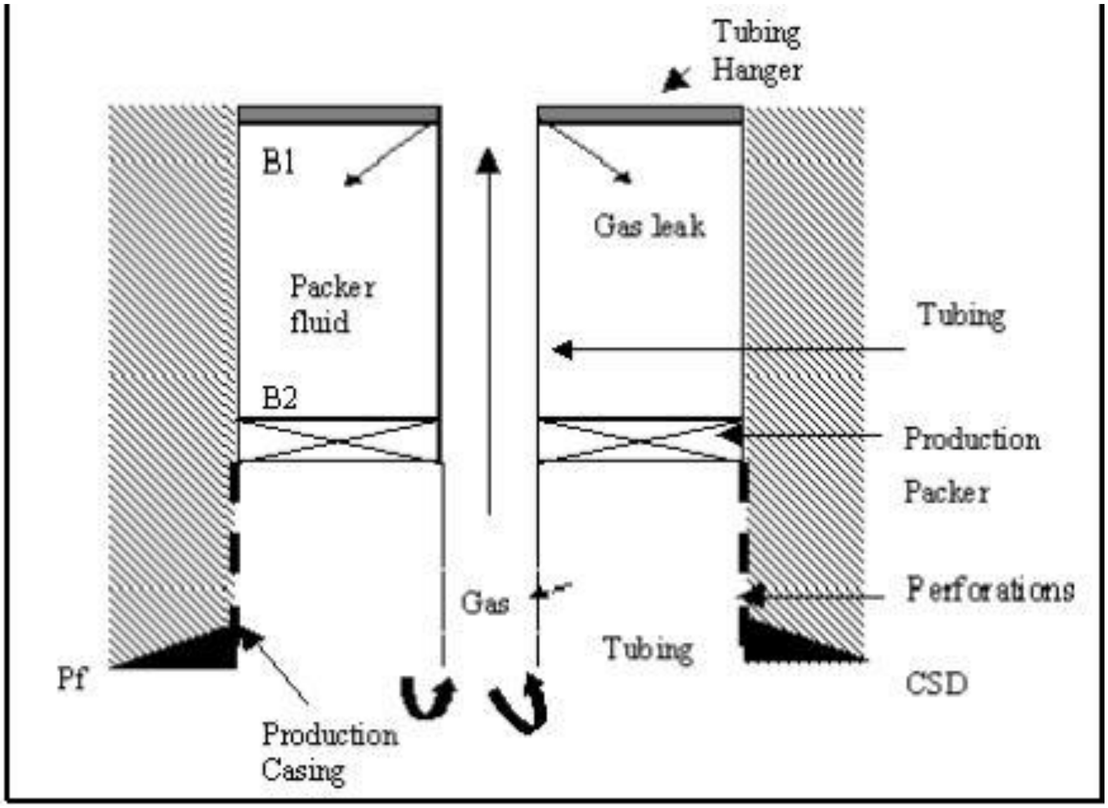

Fig.(3.3) Burst Design For Production Casing

Burst values are calculated as follows:

Burst pressure= Internal pressure - External pressure

Burst at surface (B1) =Pf - G x CSD

(or the maximum anticipated surfacepressure, whichever is the greatest)

Burst at shoe (B2) = B1 + 0.052 ρ_P x CSD - CSD x 0.465 …………….. (3.7)

Where:

G =gradient of gas, usually 0.1 psi/ft.

Pf =formation pressure at production casing seat Psi.

ρ_P =density of completion (or packer) fluid PPg.

0.465 =the density of backup fluid outside the casing torepresent the worst case, psi/ft.

Note that if a production packer is set above the casing shoe depth, then the packer depth should be used in the above calculation rather than CSD. The casing below the packer will not be subjected to burst loading (see Figure 3.3) as it is perforated.

3.3. Design & SafetyFactors:

Casings are never designed to their yield strength or tensile strength limits. Instead, a factor is used to debate the casing strength to ensure that the casing is never loaded to failure. The difference between design and safety factors is given below.

3.3.1. Safety Factor:

Safety factoruses a rating based on catastrophic failure of the casing.

$$\text{Safety Factor} = \frac{\text{Failure Load}}{\textit{Actual Applied Load}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (3.8)$$

When the actual applied load equals the failure load, then the safety factor =1 and failure is imminent. Failure will occur if the actual load is greater than the failure load and in this case the safety factor < 1.0. For the above reasons, safety factors are always kept at values greater than 1. In casing design, neither the actual applied load or failure loads are known exactly; hence design factors are used to evaluate the integrity of casing.

3.3.2. Design Factor:

Design factoruses a rating based on the minimum yield strength of casing. In the oil industry, safety factors are never intentionally used to design tubular as they imply prior knowledge of the actual failure load and designing to failure or below failure.Design factors are usually used for designing tubular and are based on comparing the maximum service load relative to the API minimum yield strength.Recall that the casing does not actually fail at the minimum yield strength and, moreover, the minimum yield strength is an average value of several measurements. Hence, the design factor provides a greater scope for safety than safety factor.

$$\text{Design Factor} = \frac{\text{Rating of the pipe}}{\text{Maximum Expected Service Load}} \qquad (3.9)$$

A Design Factor is usually equal to or greater than 1.The design factor should always allow for forces which are difficult to calculate such as shock loads.The burst design factor (DF-B) is given by:

$$\text{DF} - \text{B} = \frac{\text{Burst Strength}}{\mathit{Burst\ Pressure}\ (B)} \qquad (3.10)$$

Similarly, the collapse design factor is given by:

$$\text{DF} - \text{C} = \frac{\text{Collaose Strength}}{\mathit{Collapse\ Pressure}\ (C)} \qquad (3.11)$$

3.3.3. Recommended Design Factors:

Collapse = 1. 0

Burst = 1.1

Tension = 1.6 –1. 8

3.4. Casing Selection - Burst And Collapse:

Before a load case is applied, the casing grades/weights should initially be selected on the basis of burst and collpase pressures, then load cases should be applied. If only one grade or one weight of casing is available, then the task of selecting casing is easy. The strength properties of the casings available are compared with the collapse and burst pressures in the wellbore. If the design factors in collapse and burst are acceptable then all that remains is to check the casing for tension.

For deep wells or where more than one grade and weight are used, a graphical method of selecting casing is used as follows:

1. Plot a graph of pressure against depth, as shown in Figure 5.5, starting the depth and pressure scales at zero. Mark the CSD on this graph.

2. Collapse Line: Mark point C1 at zero depth and point C2 at CSD. Draw a straight line through points C1 and C2.

3. For partial loss circulation, there will be three collapse points. Mark C1 at zero depth, C2 at depth (CSD-L) and C3 at CSD. Draw two straight lines through these points.

4. Burst Line: Plot point B1 at zero depth and point B2 at CSD. Draw a straight line through point B1 and B2 (see Figure 3.4). For production casing, the highest pressure will be at casing shoe.

5. Plot the collapse and burst strength of the available casing, as shown in Figure5.6. In this figure, two grades, N80 and K55 are plotted to represent the available casing. Select a casing string that satisfies both collapse and burst. Figure 3.5 provides the initial selection and in many cases this selection differs very little from the final selection. Hence, great care must be exercised when producing Figure 3.5.

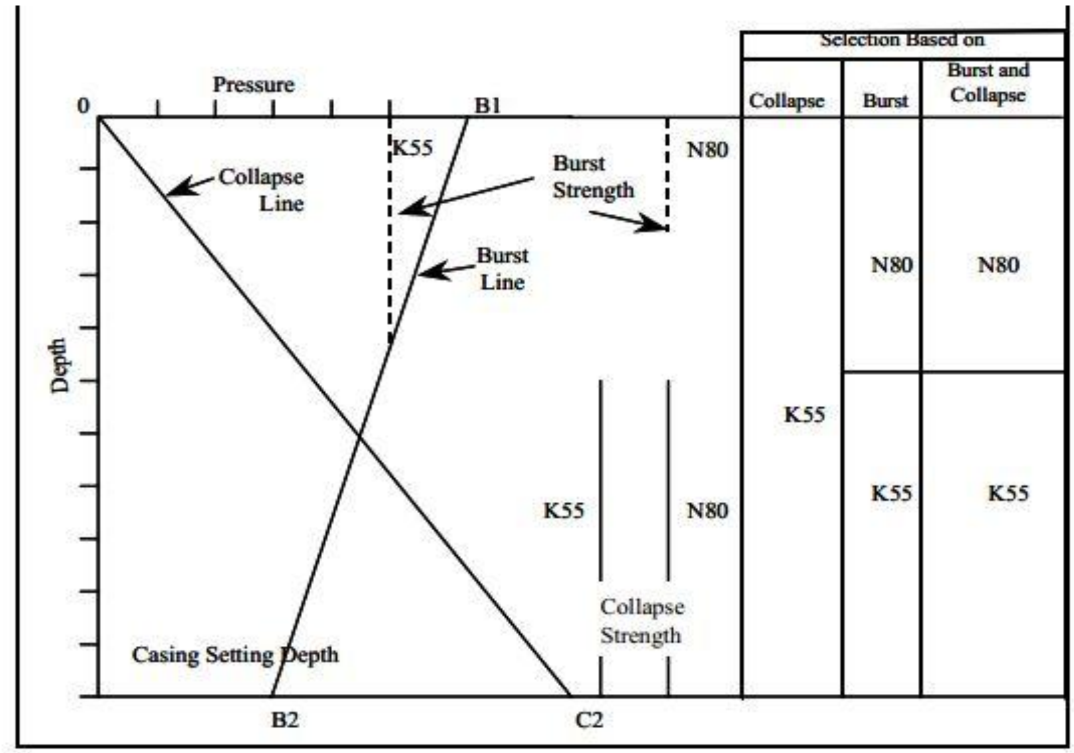

Fig.(3.4) Selection Based On Burst And Collapse

3.5. Tension:

Most axial tension arises from the weight of the casing itself. Other tension loadings can arise due to: bending, drag, shock loading and during pressure testing of casing.

In casing design, the uppermost joint of the string is considered the weakest in tension, as it has to carry the total weight of the casing string. Selection is based on a design factor of 1.6 to 1.8 for the top joint. Tensile forces are determined as follows:

1. Calculate weight of casing in air (positive value) using true vertical depth;
2. Calculate buoyancy force (negative value);
3. Calculate bending force in deviated wells (positive value);
4. Calculate drag force in deviated wells (this force is only applicable if casing is pulled out of hole);
5. Calculate shock loads due to arresting casing in slips; and
6. Calculate pressure testing forces

Forces (1) to (3) always exist, whether the pipe is static or in motion. Forces (4) and (5) exist only when the pipe is in motion. The total surface tensile load (sometimes referred to as installation load) must be determined accurately and must always be less than the yieldstrength of the top joint of the casing. Also, the installation load must be less than the rated derrick load capacity so that the casing can be run in or pulled out of hole without causing damage to the derrick.

3.5.1. Tension Calculations:

The selected grades/ weights in Figure 5.6provide the basis for checking for tension. The following forces must be considered:

Buoyant Weight Of Casing (Positive Force)

The buoyant weight is determined as the difference between casing air weight and buoyancy force.

Casing air weight = casing weight (lb/ft) x hole TVD ……………………. (3.11)

For open-ended casing, see Figure (3.5).

Buoyancy force = Pe (Ae – Ai) …………………………………………… (3.12)

For closed casing, see Figure (3.6)

Buoyancy force = PeAe – Pi Ai ………………………………………….. (3.13)

wherePe = external hydrostatic pressure, psi

Pi = internal hydrostatic pressure, psi

Ae and Ai are external and internal areas of the casing.

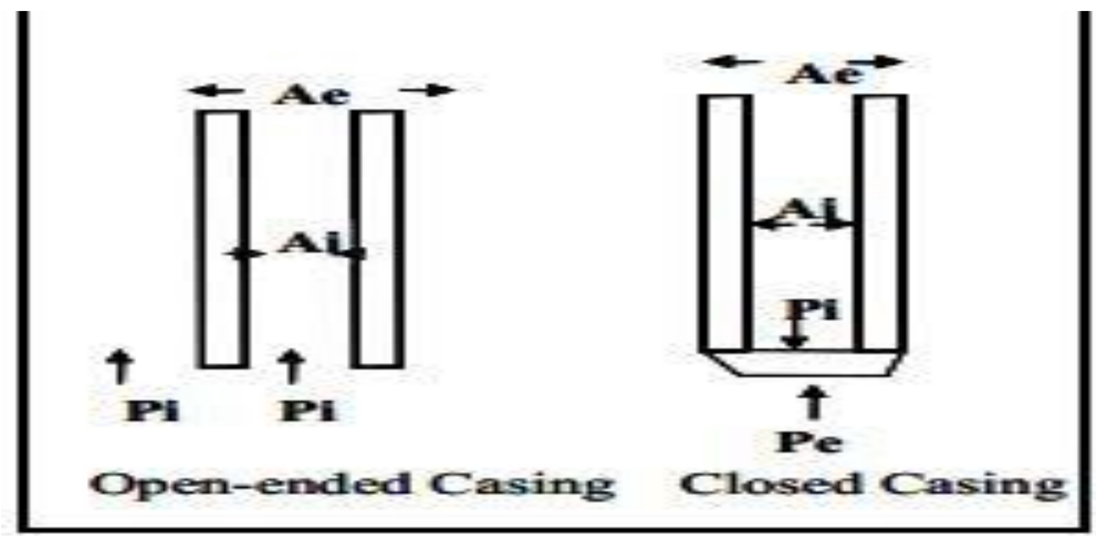

Fig .(3.5) Buoyancy Force

Since the mud inside and outside the casing is invariably the same, the buoyancy force is almost always given by Equation (3.14):

Buoyancy force = Pe (Ae – Ai) ………………………………………….. (3.14)

If a tapered casing string is used then the buoyancy force at TD is calculated as above. At a cross-sectional change, the buoyancy force is calculated as follows:

Buoyancy force = Pe2(Ae2– Ae1) – Pi2(Ai2- Ai1) ……………………... (3.15)

For most applications, the author recommends calculating the buoyant weight as follows:

Buoyant weight = air weight x buoyancy factor ………………………… (3.16)

One can easily prove that there is very little of accuracy using the above equation except for tapered strings or when the bottom of the casing is landed in compression.

2. Bending Force

The bending force is given by:

Bending force = 63 Wn x OD x θ ……………………………………….. (3.17)

where

Wn = weight of casing lb/ft (positive force)

θ = dogleg severity, degrees/100 ft

3. Shock Load

Shock loading in casing operations results when:

• Sudden decelerations are applied

• Casing is picked off the slips

• Slips are kicked in while pipe is moving

• Casing hits a bridge or jumps off an edge downhole.

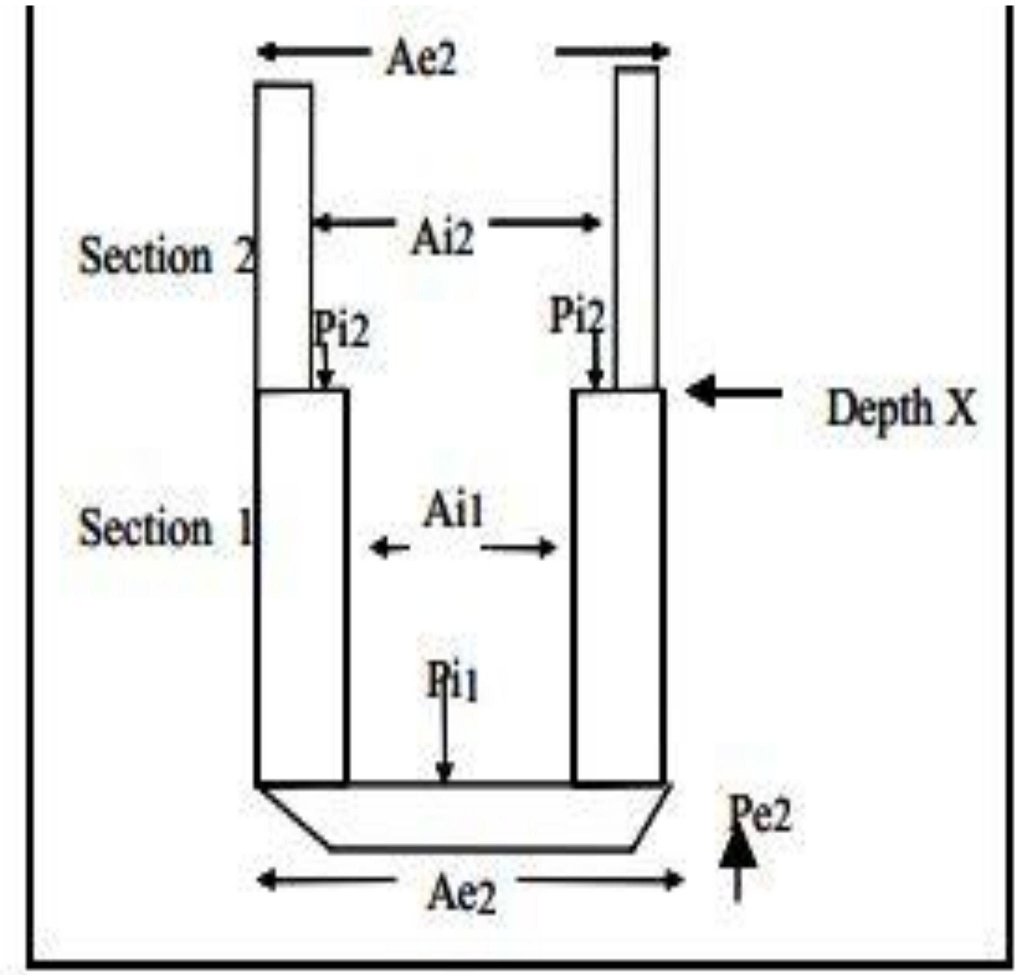

Fig.(3.6)Buoyancy Force For A tapered String

Chapter 4

Casing Design Filed Application

4.1. Filed Application:

Given the Following Data:

$9^{5}/_{8}$" Casing Size

Shoe Depth = 712 (m)

Mud Weight = 10 (ppg)

TD = 2156 (m)

G = 0.1 $^{Psi}/_{ft}$

Salt water gradient = 0.465 $^{Psi}/_{ft}$

Calculate Collapse Pressure, Burst Pressure and Tension To Select Casing Grade.

Solution

4.1.1. Collapse Pressure:

$P = 0.052 * \rho * CSD$ ……………………………….(4.1)

Assume the casing is empty (in P_i the density equal zero)

i- $C_1 = P_e - P_i$……………………………….(4.2)

$$C_1 = 0.052 * 10 * 0 - 0.052 * 0 * 0 = 0$$

Collapse at surface equal zero because the depth equal zero

ii- $C_2 = P_e - P_i$……………………………….(4.3)

$$C_2 = 0.052 * 10 * 712 * 3.281 - 0.052 * 0 * 712 * 3.281 = 1214.8\ Psi$$

4.1.2.Burst Pressure:

$B = P_i - P_e$……………………………….(4.4)

$P_{form} = 0.052 * \rho * TD$……………………………….(4.5)

$$P_{form} = 0.052 * 10 * 2156 * 3.281 = 3678.4\ Psi$$

i- $B_1 = (P_{form} - (G * TD)) - 0$……………………………….(4.6)

$$B_1 = \left(3678.4 - (0.1 * 2156 * 3.281)\right) - 0 = 2971\ Psi$$

ii- $B_2 = (P_{form} - \left(G * (TD - CSD)\right)) - (0.465 * (CSD)$…………………..(4.7)

$$B_2 = \left(3678.4 - (0.1 * (2156 - 712) * 3.281)\right) - (0.465 * 712 * 3.)$$

$$= 2118.3\ Psi$$

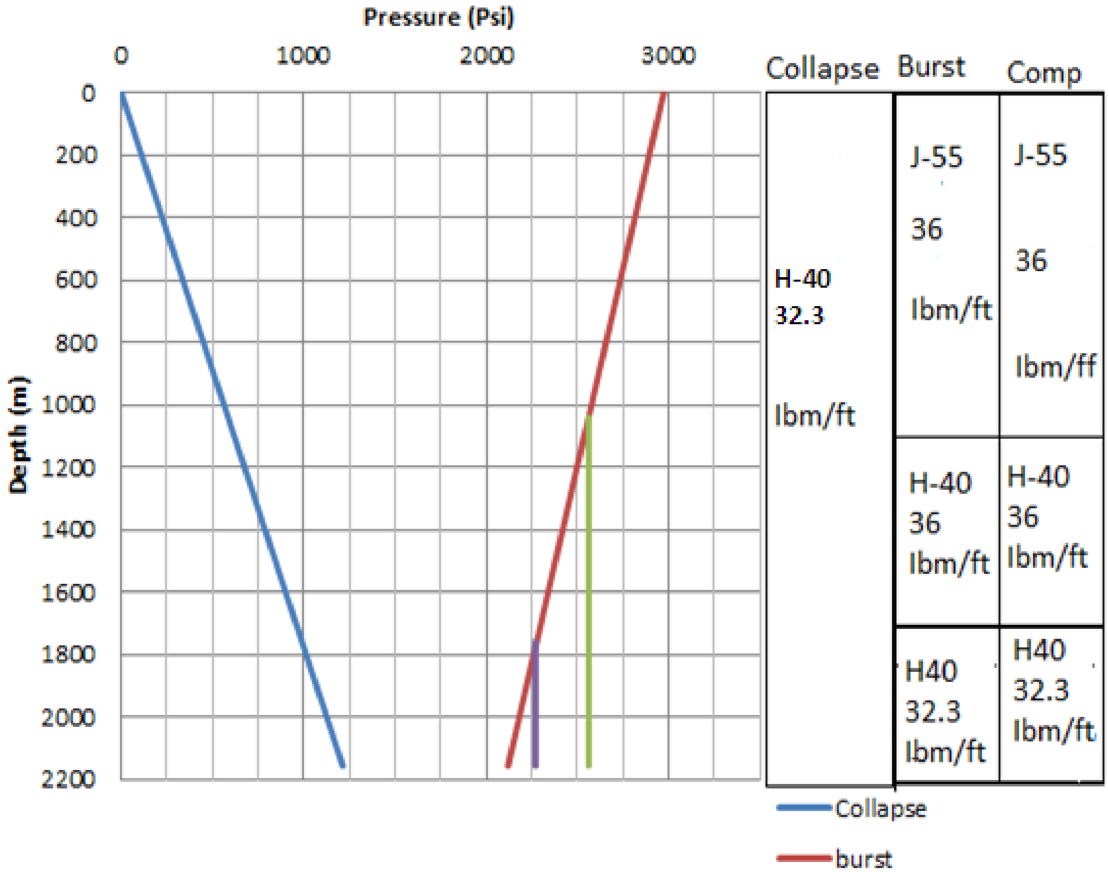

Fig.(4.1).Selection based burst and collapse.

From Plot we find that:

1-from (0-1040 m) the optimum grade is J-55 with nominal weight = $36^{Ibm}/_{ft}$

2--from (1040-1660 m) the optimum grade is H-40 with nominal weight = $36^{Ibm}/_{ft}$

3-from (1660-2156 m) the optimum grade is H-40 with nominal weight =$32.3^{Ibm}/_{ft}$

Collapse safety factor:

$$S_f = \frac{\text{collapse from table}}{\text{actual}} \quad \text{.....................................(4.8)}$$

$$S_f = \frac{2270}{1214.8} = 1.87$$

Burst Safety Factor:

$S_f = \frac{\text{Burst from table}}{\text{actual}}$……………………………..(4.9)

$$S_f = \frac{3520}{2971} = 1.2$$

5.1.3.Tension:

$T = L * wn * B_f$ ………………………………..(4.10)

$B_f = 1 - \frac{\rho_{mud}}{65.4}$…………………………………..(4.11)

$$B_f = 1 - \frac{10}{65.4} = 0.847$$

$$T = (1040 * 36 * 3.281 + 620 * 36 * 3.281 + 496 * 32.3 * 3.281) * 0.847 = 210595.4 \text{ Ibm}$$

Safety Factor:

$$S_f = \frac{\text{tension from table}}{\text{actual}}$$

$$S_f = \frac{564000}{210595.4} = 2.48$$

4.2.The previous design of casing which run in the well before completion:

$9^5/_8$" Casing Size

N-80 with nominal weight = $47^{\text{Ibm}}/_{\text{ft}}$

Collapse Safety Factor:

$$S_f = \frac{\text{collapse from table}}{\text{actual}}$$

$$S_f = \frac{4750}{1214.8} = 3.91$$

Burst Safety Factor:

$$S_f = \frac{\text{Burst from table}}{\text{actual}}$$

$$S_f = \frac{6870}{2970} = 2.31$$

Tension Safety Factor:

$$S_f = \frac{\text{tension from table}}{\text{actual}}$$

$$S_f = \frac{1086000}{332470.3} = 3.27$$

From above calculations found couldn't happen fail in this casing.

4.3. Casing Patch Design:

The corrosion depth = 4 m under the surface

1. Pipe Cutter:
   Pipe Cutter outside diameter = $8^3/_8$ in to cut 9 $^5/_8$ OD casing
   Pipe cutter tension :$T = L * wn$
   T = 4*3.281*47 = 616.8 Ibm
2. Casing Patch:
   Outside diameter = $8^1/_4$ in
   Collapse Pressure = 0
   Burst Pressure = 2971 Psi
   Tension = :$T = L * wn$
   T = (2156 – 4) * 3.281 * 47 = 331853.5 Ibm

Chapter 5

Conclusions and Recommendations

5.1. Conclusion:

After explain the general concepts of casing design.and make combination between the previous design of intermediate casing which set before completion and the new design to know the reason of decrease in pressure gauge, found that:

The casing that should be run in the well has the following properties:

- from (0-1040 m) the optimum grade is J-55 with nominal weight 36Ibm/ft
- from (1040-1660 m) the optimum grade is H-40 with nominal weight 36Ibm/ft
- from (1660-2156 m) the optimum grade is H-40 with nominal weight 32.3 Ibm/ft

The previous design which run before completion was N-80 with nominal weight 47Ibm/ft; sothe previous design is better, the problem is not caused by fail in design.

The optimum solution for this problem run casing patch with this properties:

- Outside diameter $8^1/_4$ in.
- Length 4 meter.
- Tension 331853.5 Ibm.
- Burst 2971 Psi.

5.2. Recommendation:

- ✓ All information about formations must be known.
- ✓ Set packer while production from the well.
- ✓ Good cement to the surface.
- ✓ Using corrosion preventer.
- ✓ Using alloy has high resistance to corrosion.

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