Chair of Petroleum and Geothermal Energy Recovery

Master Thesis

Characterization of the Criteria and Conditions in Sweet and Sour Borehole Environments for the Materials Selection and Design of Sand Retention Devices

Written by:
Parham Bekhrad, BSc
1135520

Advisor:
Univ.-Prof. Dipl.-Ing. Dr.mont. Herbert Hofstätter
Dipl.-Ing. Dr.mont. Marianne Kapp
Univ.-Prof. Dipl.-Ing. Dr.mont. Markus Oberndorfer

Leoben, 01.09.2016

EIDESSTATTLICHE ERKLÄRUNG

Ich erkläre an Eides statt, dass ich die vorliegende Diplomarbeit selbständig und ohne fremde Hilfe verfasst, andere als die angegebenen Quellen und Hilfsmittel nicht benutzt und die den benutzten Quellen wörtlich und inhaltlich entnommenen Stellen als solche erkenntlich gemacht habe.

AFFIDAVIT

I hereby declare that the content of this work is my own composition and has not been submitted previously for any higher degree. All extracts have been distinguished using quoted references and all information sources have been acknowledged.

Danksagung / Acknowledgement

Firstly, I would like to thank Prof. Herbert Hofstätter and Sepp Steinlechner from Production Engineering Department of Montanuniversität Leoben. This thesis would not have been possible without your help, advice and support. I would like to thank H/Prof. Markus Oberndorfer, Dr. Marianne Kapp, and BÖHLER Edelstahl Co. (Kapfenberg) for supervising this thesis. I would also like to recognize the effort of Dr. Mohammad Sedaghat, Hamidreza Nejad Karimi and Alireza Bekhrad who worked with me during this project.

Finally, I would like to thank my family, especially my parents and my brother for all the support they have provided me over the last nine months.

Kurzfassung

In der Erdöl- und Erdgasindustrie, ist der Sandproduktion eines der Probleme, dasErdöl- und Erdgasfirmen große Geldsummen kostet. Aufgrund derletzten Entwicklungen in der Bohrtechnik, sind jetzt tieferen Formationen leichter erreichbar, und deswegen sind Materialien die solche Umgebungen wiedersten gebraucht. Diese Umgebungen bestehen haupsachlich aus Kombinationen aus H_2S, CO_2 hoher Temperatur und hohem Druck, deswegen ist eine vertiefende Untersuchung für die geeignete Materialien erforderlich.

In dieser Masterarbeit werden verschiedene Sandkontrollverfahren und die dazu verwendeten Materialien, veranschaulicht . Eines dieser Materialien, das in verschiedenen Bereichen der Erdöl- und Erdgasindustrie wervendet wird , ist Legierung 316L. Hier wird diese Legierung mit 12 anderen Legierungen, die am häufigsten beim sand screen manufacturing für süß und sauer Bedingungen verglichen.

Die Ergebnisse dieser Bewertungen zeigen, dass Legierung 316L nicht geeignet ist für stark korrosive Medien, wie Umgebungen, die H_2S oder CO_2 enthalten. Es wird deswegen empfohlen andere Legierungen, die solche Umgebungen aushalten, zu verwenden. Nach einer detaillierten Forschung in der Widerständigkeit gegen Korrosion in verschiedenen physikalischen Bedingungen und mechanischen Eigenschaften von verschiedenen Materialien, wurde festgestellt, dass C276 bei weitem die beste Option unter allen Legierungen , die von Erdölfirmen berücksichtigt sein soll. Obwohl alle anderen Legierungen schlechtere mechanischen Eigenschaften als C276 haben, bieten sie eine billigere Alternative in bestimmten physikalischen Bedingungen und Umgebungen.Firmen können ein optimales Gleichgewicht zwischen Kosten und Qualität der Lösung erstellen, indem sie die detaillierten Eigenschaften der Arbeitsumgebung berücksichtigen, und danach die dafür geeignete Material wählen.

Abstract

In oil and gas industry, sand production is one of the problems costing oil and gas companies large sums of money. Due to recent developments in drilling technology, deeper formations can now be reached, and as a result new materials that can withstand these environments are desirable. These environments are predominantly combinations of CO_2, H_2S, high temperature and high pressure, hence further investigation into appropriate materials is required.

In this master thesis, different sand control methods are introduced and typical materials which are generally used for these methods are listed. One of these materials used in different sectors of oil and gas industry, especially in sand screens is alloy316L. Alloy316L and 12 other alloys that are most common in sand screen manufacturing for sweet and sour conditions are compared.

The results of these assessments show that alloy316L is not a suitable option for highly corrosive media such as environments containing H_2S and CO_2. It is suggested that other superior alloys that can withstand these environments are used instead. After detailed research into corrosion resistance in different physical conditions and mechanical properties of a set of candidate materials, it was found that C276 is by far the best option among all alloys that can be considered by oil companies. Although all other candidate alloys have mechanical properties inferior to C276, each provide a cheaper alternative in certain physical conditions and environments. Companies could achieve an optimum balance between cost and quality of the solution by taking into account the detail properties of the working media and then choosing the most appropriate material accordingly.

List of Tables

Table 4-1.Critique of different sand prevention methods [6]....10

Table 4-2 Current ESS systems [21] 26

Table 4-3 Circulating OHGP versus alternate path....31

Table 5-1Galvanic Series of Metals and Alloys in Seawater [33] 38

Table 6-1 Guidance on the use of materials selection tables of Annex A based on equipment or component type....59

Table 6-2 Austenitic stainless steels composition....59

Table 6-3 Highly-alloyed Stainless Steels composition....62

Table 6-4 Ferritic Stainless Steels composition 65

Table 6-5 Martensitic Stainless Steels composition....65

Table 6-6 Chemical composition of Böhler Edelstahl Company alloys....74

Table 6-7 Comparison of different alloys 76

Table 8-1 Sand screens suppliers [19] 83

List of Figures

Figure 2-1: One section of a sand screen before erosion [1] 3

Figure 2-2: One section of a sand screen after erosion [2] 3

Figure 4-1 Sand Control Completion Methods... 8

Figure 4-2 Reservoir completions methods 9

Figure 4-3 Gravel, Sand, Silt and Clay sizes 11

Figure 4-4.Dry sieve device [9]..12

Figure 4-5 Laser Particle Size distribution process [10] 13

Figure 4-6 LPSA versus DSA [12] 14

Figure 4-7 Uniformity Coefficient Examples [12]..14

Figure 4-8 Slotted-liner geometry [6] 15

Figure 4-9 Keystone shaped slots 15

Figure 4-10 Straight shaped slots..16

Figure 4-11 Wire-wrapped screen 16

Figure 4-12 Examples of wire-wrapped screen inflow area [3]..17

Figure 4-13 Wire-wrapped screen 17

Figure 4-14 Wire-wrap screen illustrations [13]..18

Figure 4-15 LR: Dual-screen pre-packed, Single-screen pre-packed and Slim-packed [6] ...19

Figure 4-16 Pre-packed screens [16]..19

Figure 4-17 Pre-packed screen vertical view and side view [18]..20

Figure 4-18 Pre-packed screen illustrations [13]...20

Figure 4-19 LTR: Sintered Metal Screen, Strata pack Screen, and Excluder Screen............21

Figure 4-20 Wire weave patterns and sizes [19]..22

Figure 4-21 Metal-mesh screen illustrations [13] 23

Figure 4-22 A partially expanded ESS..24

Figure 4-23 ESS construction [21]..24

Figure 4-24 ESS installations by completion type and footage [21] 25

Figure 4-25 Current ESS open-hole installations by application 26

Figure 4-26 Erosive failure of a wire-wrapped screen [23]..27

Figure 4-27 Collapse failure of a wire-wrapped screen jacket [23].......................................28

Figure 4-28 Screen wire-wrapped failure [23]...29

Figure 4-29 Microscopic evaluation after static test on different gravels [25] 30

Figure 4-30 Evaluation of permeability in glass beads and ceramics [25] 30

Figure 4-31 OHGP (Left) and CHGP (Right)..33

Figure 5-1 Uniform attack of pipeline exterior beneath debonded pipeline coating [31] 37

Figure 5-2 Galvanic corrosion of galvanized piping in connection with bronze valve[31].......37

Figure 5-3 Pit morphology [31] 39

Figure 5-4 Pitting corrosion of an Alloy825 heat exchanger baffle exposed to seawater [31]40

Figure 5-5 Crevice corrosion locations on a bolted connection 41

Figure 5-6 Multiphase fluid flow regimes in straight runs of vertical or horizontal piping [31].42

Figure 5-7 Critical factors for SCC 44

Figure 5-8 Clustered "colonies" of SCC on the outside of a carbon steel Pipeline[31] 44

Figure 5-9 Small cracks joining together and intersecting circumferential cracks on the exterior of a pipeline[31] 45

Figure 5-10 HIC in sour service [36] 46

Figure 5-11 Schematic representation of an electrochemical cell for CO_2 corrosion on a steel surface [38] 48

Figure 5-12 The effect of dissolved gases on the corrosion of carbon steel [31]...................49

Figure 5-13 The effect of pH on the corrosion rate of iron in water at room temp. [41]..........51

Figure 5-14 Geothermal gradient illustration [44]..52

Figure 5-15 HPHT definition [45] 52

Figure 6-1 FCC crystal structure..60

Figure 6-2 BCC crystal structure 64

Figure 6-3 The corrosion resistance of Alloy 316/316L in CO_2/NaCl environments in the absence of oxygen and H_2S. Corrosion rates of ≤0.05 mm/yr. (2mpy) and no SSC or SCC [51] 68

Figure 6-4 The corrosion resistance of Alloy 13Cr in CO_2/NaCl environments in the absence of oxygen and H_2S. Corrosion rates of ≤0.05 mm/yr. (2mpy) and no SSC or SCC [51]..69

Figure 6-5 Limits for 13Cr in Sour Service [51] 69

Figure 6-6 SSC susceptibility diagram of a S13Cr.[52] 70

Figure 6-7 The corrosion resistance of 22Cr duplex in CO_2/NaCl environments in the absence of oxygen and H_2S, Corrosion rates of ≤0.05 mm/yr. (2mpy) and no SSC or SCC [51] 71

Figure 6-8 The corrosion resistance of Alloy28 in H_2S/CO_2 environments in the absence of elemental sulphur, Corrosion rates of ≤0.05 mm/yr (2mpy) and no SSC or SCC [51]....72

Figure 6-9 The corrosion resistance of Alloy625 in H_2S/CO_2 environments in the absence of elemental sulphur, Corrosion rates of ≤0.05 mm/yr (2mpy) and no SSC or SCC [51]....72

Figure 6-10 The corrosion resistance of Alloy825 in H_2S/CO_2 environments in the absence of elemental sulphur, Corrosion rates of ≤0.05 mm/yr (2mpy) and no SSC or SCC [51]....73

Figure 6-11 The corrosion resistance of Alloy2550 in H_2S/CO_2 environments in the absence of elemental sulphur, Corrosion rates of ≤0.05 mm/yr (2mpy) and no SSC or SCC [51] 73

Figure 6-12 The corrosion resistance of Alloy C-276 in H_2S/CO_2 environments in the absence of elemental sulphur, Corrosion rates of ≤0.05 mm/yr (2mpy) and no SSC or SCC [51] 74

Figure 7-1 Sand control systems market (2014 VS 2019) [56]..77

Figure 7-2 Sand control systems market, by application [56]..78

Figure 7-3 Sand control systems global market share in 2014 and expected CAGR% [56] ..79

Figure 7-4 Sand control systems market size, by type, 2012-2019 ($ Million) [56]................80

Figure 7-5 Gravel pack market size, by region, 2012-2019 ($ Million) [56] 81

Figure 7-6 Sand screens market size, by region, 2012-2019 ($ Million) [56].........................82

Figure 8-1Sand Screens Products by Type 85

Figure A-1 Mesh sizes and gap dimensions [3] 92

Abbreviations

WWS	Wire-Wrapped Screen
PPS	Pre-Packed Screen
PSD	Particle Size Distribution
LPS	Laser Particle Size
OHGP	Open Hole Gravel Pack
CHGP	Cased Hole Gravel Pack
ESS	Expandable Sand Screen
CRA	Corrosion Resistant Alloys
SCC	Stress Corrosion Cracking
SSC	Sulfide Stress Cracking
PREN	Pitting Resistance Equivalent Number
CPT	Critical Pitting Temperature
EOR	Enhances Oil Recovery
NACE	National Association of Corrosion Engineers
API	American Petroleum Institute
HSCC	Hydrogen-assisted Stress Corrosion Cracking
HE	Hydrogen Embrittlement
PWHT	Post Weld Heat Treatment
HIC	Hydrogen Induced Cracking
HPHT	High Pressure High Temperature
HAZ	Heat Affected Zone
FCC	Face-Centred Cubic
BCC	Body-Centred Cubic
CAGR	Compound Annual Growth Rate

Table of content

Page

1 INTRODUCTION 1

2 SAND PRODUCTION..2

2.1 Causes of Sand Production 2

2.2 Consequences of Sand Production...2

2.2.1 Accumulation in surface equipment 2

2.2.2 Accumulation in downhole section 3

2.2.3 Erosion of downhole and surface equipment...3

2.2.4 Collapse of the formation 4

3 SAND PRODUCTION PREDICTION...5

3.1 Formation strength and sand movement 5

3.2 Core-derived strength measurements..6

3.3 Log-derived strength measurements 6

4 SAND CONTROL 8

4.1 Completion...8

4.2 Completions types 8

4.2.1 Sand control completion consideration...9

4.3 Sand control methods 10

4.3.1 Formation grain size distribution 11

4.3.1.1 Dry Sieving Analysis (DSA)...12

4.3.1.2 Laser Particle Size Analysis (LPSA)...13

4.3.2 Sand Control Screens and Slotted liners..14

4.3.2.1 Wire-wrapped Screens (WWS) 16

4.3.2.2 Pre-packed Screens (PPS) 18

4.3.2.3 Premium Screens 21

4.3.2.4 Expandable Sand Screens (ESS) 23

4.3.2.5 Sand Screens Common Problems 27

4.3.3 Sand Control Gravel Packs..29

4.3.3.1 Gravel Selection..29

4.3.3.2 Open-Hole Gravel Packs (OHGP)..31

4.3.3.3 Cased-Hole Gravel Packs (CHGP) 32

4.3.3.4 Frack Packs 33

5 CORROSION 34

5.1 Introduction 34

5.2 The Chemistry of Corrosion 35

5.3 Forms of Corrosion 36

5.3.1 Uniform attack (General corrosion) 37

5.3.2 Galvanic Corrosion 37

5.3.3 Pitting Corrosion 39

5.3.3.1 Pitting Resistance Equivalent Numbers (PRENs) 40

5.3.3.2 Critical Pitting Temperature (CPT) 41

5.3.4 Crevice Corrosion 41

5.3.5 Erosion-Corrosion 42

5.3.5.1 Velocity Effects on Erosion-Corrosion 42

5.3.6 Stress Corrosion Cracking (SCC) 43

5.3.7 Hydrogen-Induced Cracking (HIC) 46

5.3.8 Sulfide Stress Cracking (SSC) 47

5.3.9 Sweet Corrosion – CO_2 Corrosion 47

5.3.10 Sour Corrosion – H_2S Corrosion 49

5.4 Down-hole Corrosion 50

5.4.1 Environmental Factors 50

5.4.1.1 pH 51

5.4.1.2 Temperature Effect 51

5.4.1.3 Pressure Effect 52

5.4.1.4 Salinity 53

5.4.1.5 Chloride Content 53

5.4.1.6 H_2S Partial Pressure 54

5.4.1.7 CO_2 Partial Pressure 54

6 MATERIALS SELECTION 55

6.1 Introduction to NACE Standard 55

6.1.1 Test Method 55

6.1.2 Standard Practice: 55

6.1.3 Material Requirements 56

6.1.3.1 NACE MR0175/MR0103 56

6.1.3.2 NACE MR0175 56

6.2 Material Groups 58

6.2.1 Austenitic Stainless Steels 59

6.2.2 Highly-alloyed Austenitic Stainless Steels 62

6.2.3 Ferritic Stainless Steels 64
6.2.4 Martensitic Stainless Steels 65
6.2.5 Duplex Stainless Steels 65
6.2.6 Precipitation-Hardened Stainless Steels ....**Error! Bookmark not defined.**
6.2.7 Nickel-based Alloys....66
6.3 Sand Screens Material Selections 67
6.3.1 316L (Austenitic Stainless Steel)....67
6.3.2 13Cr & S13Cr (Martensitic Stainless Steel)....68
6.3.3 22Cr & 25Cr (Duplex Stainless Steel) 70
6.3.4 Alloy20 (Solid Solution Nickel-based Alloys) 71
6.3.5 Alloy28 (Solid Solution Nickel-based Alloys) 71
6.3.6 Alloy625 (Solid Solution Nickel-based Alloys) 72
6.3.7 Alloy825 (Solid Solution Nickel-based Alloys) 73
6.3.8 Alloy2550 (Solid Solution Nickel-based Alloys) 73
6.3.9 Alloy C-276 (Solid Solution Nickel-based Alloys) 74
6.3.10 Alloy A975 Extra & P560 Extra (BÖHLER Edelstahl) 74
6.4 Sand Screens Material Selections Results 75
7 SAND SCREENS MARKET SHARE....77
7.1 Sand Control Systems Market (2014 VS 2019) 77
7.2 Sand Control Systems Market Size, by Type (2014 to 2019) 80
7.2.1 Gravel Pack Systems Market Size, (2014 to 2019)....81
7.2.2 Sand Screens Market Size, (2014 to 2019)....82
8 SAND SCREENS SUPPLIERS 83
9 CONCLUSION....86
10 REFERENCES ....ERROR! BOOKMARK NOT DEFINED.
A. APPENDICES 92
B. APPENDICES 93

1 Introduction

Sand production is a major problem in the production of hydrocarbons from unconsolidated and sandstone reservoirs. Commonly, sand production occurs when a destabilizing action exceeds or removes the forces which hold sand grains together. The consequences of such phenomena can be accumulation of sand in surface equipment or in downhole section of the well, erosion of downhole and surface equipment or even in extreme cases, collapse of the formation which could cost companies large sums of money. Hence, sand production must be safely controlled. There are a multitude of methods for preventing or controlling sand production, namely, installing *sand control screens and slotted liners* or *sand control gravel packs*. Deploying these methods can filter the sand particles and protect the equipment from erosion caused by sand particles. The recent increase in demand for energy as well as the depletion of existing oil and gas deposits is causing the service companies to explore deeper reservoirs and more challenging downhole environments. As a result, these companies are faced with more complex design decisions when choosing the appropriate materials and equipment. The conditions these new materials must withstand are a mixture of high pressure high temperature (HPHT) with Hydrogen Sulphide (known as Sour environment), Carbon Dioxide (known as Sweet environment) and chloride contents. In this field, designing a sand retention device that can tolerate the mentioned conditions is the key to solving sand production problems.

The aim of this master thesis is to find a material or materials that can resist sweet and sour conditions when used as sand screens. In Chapter 2, sand production is introduced and its causes and consequences in oil and gas fields are discussed. In Chapter 3, we will have an overview of methods commonly used to predict sand production by core-derived strength and log-derived strength measurements. Chapter 4 will discuss the methods for controlling the produced sands using screens, slotted liners, cased-hole and open-hole gravel packing, frack-packing. Furthermore, an introduction of different sand screens such as Wire-wrapped and Pre-packed as well as their corresponding downsides will be provided. In Chapter 5, we will have a discussion about corrosion, its chemistry and different types of corrosions occurring in oil and gas fields, environmental factors which must be taken into account for designing the materials to be used in sand screens. In Chapter 6, an introduction to material selection methods using NACE standards as well as characterization of different material groups is provided. Thirteen different alloys from different material groups are chosen for further assessments and comparison based on their corrosion and mechanical properties. Finally, a comprehensive table summarizing the result of these assessments is presented. Chapters 7 and 8 will cover the noteworthy sand screens suppliers and their corresponding share in the market.

2 Sand Production

As one of the big challenges facing oil and gas industry, sand production poses serious problems especially when it comes to production in sandstone reservoirs. Given its features during oil and gas production, sand production can be grouped into 3 types as follows: 1-unstable sand production which has a low risk, 2-continuous sand production with high risk, and 3- disastrous high-rate sand production with ultra-high risk. It is worth noting that all 3 types can result in huge destruction and hefty losses for oil and gas industry. Similarly, a lot of gas and oil wells experience the problems related to sand production (especially, for wells used to extract products from incompetent reservoirs or those reservoirs in which pressure has been depleted). Due to its effect on completion and surface equipment, sand production raises very serious concern. It may end up deconsolidating the formation with a potentially disastrous collapse.

2.1 Causes of Sand Production

Broadly speaking, sand production happens due to the effect of a destabilizing action that exceeds or removes the forces, resulting in conglomeration of grains. Drag force that results from produced or injected fluids is another factor contributing to the sand production. This may loosen the intergranular cement bonds, destroying the natural arches of unconsolidated sands. As another cause of sand production, unconsolidated fine collector can result in the sands being held together. Fourth cause of the sand production is an extreme rise in drawdown while the well is being developed and operated Furthermore the old reservoirs from any type can cause sand production due to overburden pressure and the chance of collapsing.

2.2 Consequences of Sand Production

Sand production can cause destructive impacts on the short-long-term productivity of the well. Despite the fact that some wells normally face manageable sand production, yet the number of such wells is few. In the majority of cases, efforts to control sand production during the life of the well are not considered as an appealing or prudent operating alternative.

2.2.1 Accumulation in surface equipment

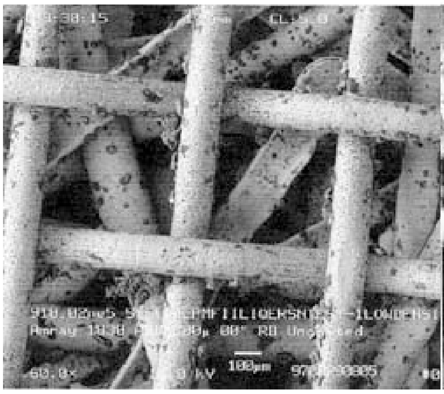
The sufficient velocity of the production which results in the transportation of the sand to the surface causes the sand to be trapped in the separator, heater treater, or production flowline. When a large amount of sands is trapped in one of these areas, the well needs to be cleaned in order to keep on the efficient production of the well. The restoration of production entails taking the following measures: the well should be closed, the surface equipment should be uninstalled, and the sand should be manually removed. The costs of the delayed production as well as the cost of cleaning need to be considered.

2.2.2 Accumulation in downhole section

The insufficient velocity of the production in well tubulars to transport sand to the surface will cause the inside of the casing to be filled with sand. Finally, the sand may thoroughly cover the producing interval. This will result in the decline of the production rate so that the well will become “sanded up” and production will stop. In such circumstances, remedial operations are needed to clear the well in order to restore productivity. To this end, various techniques can be used such as running a “bailer” on a wireline to clear the sand from the production tubing or casing. Since the bailer clears only a small amount of sand at a time, the thorough cleaning-out entails multiple wireline runs. As another cleanout technique, a smaller diameter tubing string or coiled tubing can be run into the production tubing to shake off the sand and remove it out of the well by circulating fluid. The inner string should be gradually lowered so that it can circulate the sand out of the well. Cautions need to be taken to prevent the sticking of the inner string inside the production tubing. Should the sand production be continuous, the cleanout activities are required periodically (e.g. once a month or week). This can lead to production loss and an increase in well maintenance costs.

2.2.3 Erosion of downhole and surface equipment

Sand-laden fluids which emerge as the result of turbulent flow are highly erosive. An example of an eroded section of a well screen being exposed to a perforation that was producing sand prior to and following erosion is shown in Figure 2-1 and Figure 2-2.The severe or long erosion can result in thorough failure of surface and/or downhole equipment. This may lead to serious safety and environmental problems as well as delayed production. Erosion will be discussed in detail in chapter 5 of this thesis.



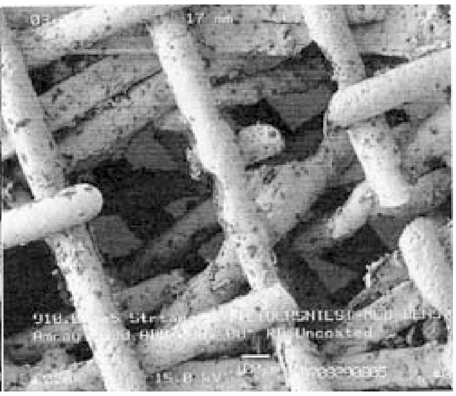


Figure 2-1: One section of a sand screen before erosion [1]

Figure 2-2: One section of a sand screen after erosion [2]

2.2.4 Collapse of the formation

The voluminous production of sand may lead to the collapse of the formation around the well. Seemingly, the formation and widening of a void reduce the supporting capability of overlying formations. This, in turns, results in the collapse due to a lack of material to provide support. The occurrence of the collapse allows the sand grains to rearrange themselves, leading to the creation of a lower permeability than before. The formation sand with a high clay content or wide range of grain sizes are especially subject to these conditions. In contrast, in the case of a formation that has a narrow grain-size distribution (well sorted) and/or very little clay, the rearrangement of formation sand results in a reduced permeability which is not as severe. The collapse of the overlying shale may lead to a complete loss of productivity. In the majority of cases, continued long-term production of formation sand normally reduces the productivity of the well and its ultimate recovery.

The collapse of the formation particularly becomes critical to well productivity if the formation material fills the perforation tunnels. Even a small amount of formation material filling the perforation tunnels will lead to a significant increase in pressure drop across the formation near the wellbore for a given flow rate. Given these negative outcomes of sand production, the best solution regarding sand production is to control it downhole.

3 Sand production prediction

Generally, the following 3 major factors can be used to predict the sand production[3]. 1. *Rock strength* 2. *Regional stresses* 3. *Local loads*

Rock strength is closely concerned with the diagenesis and lithification of the mineral grains. These concepts involve the changes a rock undergoes such as deposition, burial, compaction and cementation as well as the transformative processes which turn loose grains into solid rock. Overall, it is shown that older rock formations are harder compared to younger rock formations. This is because the older rock normally has been buried more deeply and it is more compacted. Yet, this may not be true when the rock is shielded against the compaction and cementation. Analysis of core samples is the most accurate method used to determine rock strength. Yet, it takes a lot of time and money to implement such a method. Consequently, as an alternative method commonly used, the rock strength is interpreted and estimated from MWD- or wireline-logs.

Regional stresses involve the in-situ stresses a rock encounters. There are basically the following 3 principal stresses when it comes to rock context: 1. the Vertical stress represented by σ_v; 2. the Maximum horizontal stress represented by σ_H, and 3. the Minimum horizontal stress represented by σ_h. The vertical stress is concerned with the overburden load a rock is subjected to, namely, the weight of the overlying rock (together with hydrostatic column in the case of an offshore well) [3]. The tectonic activity can affect these stresses in the region so that one can identify whether there is a typical tectonic regime, a strike-slip tectonic regime or a thrust tectonic regime given the size of the stresses. In particular, thrust regimes which involve the greater size of the two horizontal stresses than the vertical stress, pose known challenges regarding drilling and wellbore stability. These problems may result in the production of sand in the production phase [3] The following tests can be used to measure σ_h: Leak-Off Tests, Extended Leak-Off Tests or Mini-Frac Tests. The estimation of the maximum horizontal stress σ_H can also be done, using The Extended Leak-Off Test and Mini-frac test [4].

Local loads involve the processes which the rock undergoes because of the well drilling, namely, flow, reduced pore pressure and reaction of water with the minerals of the rock.

3.1 Formation strength and sand movement

It is of enormous importance for oil and gas companies to predict production of sand in order to reduce the damages to the equipment and well bore. Consequently, a completion engineer needs to have adequate knowledge on the formation they are producing from as well as the circumstances under which offset wells are operating in order to verify the possibility of sand production. The following considerations should be included in the case of sand production:

- Overall, rocks with strength below 1000 psi may need to be controlled for sand production.
- If the drawdown is almost 1.7 times bigger than the compressive formation strength, the rock will fail.
- By using the sonic-log we can simply understand which types of formations we are dealing with, if our data extracted from sonic-log is more than 120 sec. our formations condition is near unconsolidated which we have to make sure we are using proper sand control technique. If the extracted data is around 90 sec. our formation is a weak formation and if our data is less than 50 sec. our formation is strong enough that we don’t need sand control for.
- The formations with more than 30% of porosity are believed to be unconsolidated and have the highest potential for sand production. Formations with a range of porosity between 20%-30% fall in grey area and we need to pay more attention to them. Finally, formations with porosity less than 20% are stronger formations and consequently they may are less worrisome.

.

3.2 Core-derived strength measurements

Normally, core experiments are used to estimate rock strength. As the cost of accessing core is high and given that it is difficult to convince drilling engineers that coring is worthwhile, core is both valuable and sparse. Moreover, core handling, mud filtrate, storage method and desiccation can negatively influence rock strength, thus we need to carefully select samples to make sure that they represent the materials we need to test. Rock strength tests entail selection of rather large pieces of core than with standard poroperm plugs. Moreover, as they are destructive in nature, almost few tests per well will be conducted. Consequently, they are mainly intended to offer frequently calibration points for other methods such as log-derived strengths. Several strength experiments can be conducted, with the simplest one being unconfined compressive strength (UCS) measurements [3]. The unconfined compressive strength (UCS) is considered as the maximum axial compressive stress that a right-cylindrical sample of material can resist against under unconfined conditions—the confining stress is zero. It is also named as the *“uniaxial compressive strength*” of a material since the application of compressive stress is only along one axis—the longitudinal axis—of the sample.

3.3 Log-derived strength measurements

The assessment of rock strength can be carried out, using log data. We can best use Logs when they are calibrated to core data (e.g. when there is no direct relationship between any wireline-derived data and rock strength) [5]. Being cheap and accessible are the main advantages of log-derived measurements. When tuned, they serve as near-continuous measurements and can provide a profile of the strength through the reservoir. Porosity (either neutron or density logs) and the sonic log are the wireline logs most frequently used for strength estimation. These logs are normally run by measurement while drilling (MWD) or through a dedicated wireline run. [3]

4 Sand control

Sand control is referred to all the physical measures that can be used to prevent sand from being produced. This may be a sand control tool, such as a screen, or gravel slurry which is being pumped into the reservoir interval to filter out the sand grains - most commonly a gravel pack or a frac-pack. Techniques such as selected and oriented perforations or perforating the strongest and most competent reservoir intervals are also a form of sand control. A distinction can be made between cased-hole completions and open-hole completions, although some of the tools and techniques can be utilized in both types of completions. As a general rule it can be said that a cased-hole completion is the most reliable as the casing or liner will provide support for the borehole wall and protection for the completion tools. At the same time cased-hole completions are usually associated with higher skin, i.e. lower production rates. Open-hole completions on the other hand provide no support for the borehole wall or protection for the completion tools, but are usually associated with zero or negative skin factors and are preferable if applicable. This is going to be discussed in this chapter consist

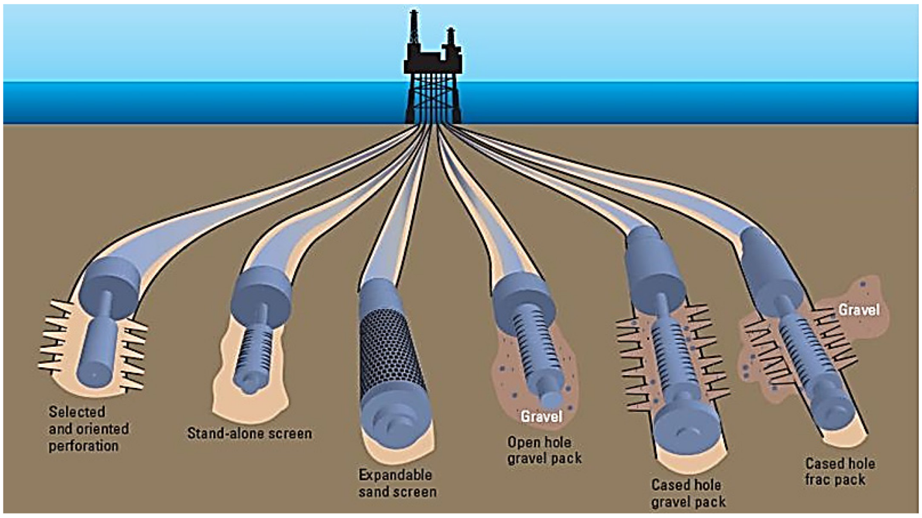


Figure 4-1 Sand Control Completion Methods

4.1 Completion

The interface between the reservoir and surface, ensuring safe and efficient production, is known as the completion. Its role is crucial regarding the economics of a field development. When the field is starting to produce one can see the importance of a successful completion.

4.2 Completions types

The wells which are completes are either injectors or producers. By using completion, these wells can produce water or hydrocarbons or inject water, hydrocarbons, steam and waste products like carbon dioxide. A well can also serve more than one purpose, e.g. it is possible to combine production and injection by producing through the tubing while injecting down the annulus.

We normally divide completions into one lower completion and an upper completion. The lower completion is the connection between the well and the reservoir, while the upper completion is given as the interface between conduits from reservoir completion to surface equipment.

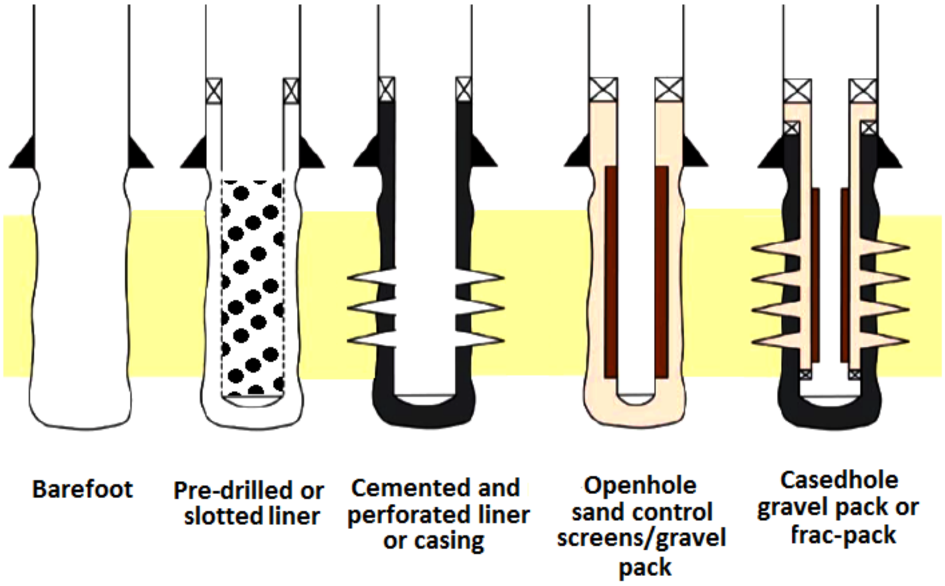


Figure 4-2 Reservoir completions methods

Some of the key decisions in the reservoir completion are: 1. Well trajectory and inclination 2. Open hole versus cased hole 3. Sand control requirement and type of sand control 4. Stimulation (acid or proppant) 5. single or multi-zone (commingles or selective)

4.2.1 Sand control completion consideration

For selecting the appropriate completion method, we have to consider:

- Design complexity
- Installation complexity
- Mechanical robustness
- Sanding risk
- Plugging risk
- Erosion risk
- Well productivity
- Total cost.

4.3 Sand control methods

There are several methods which can control the sand production. These methods are:

- Chemical consolidation.
- Screens, slotted liners, special filters (including expandable screens)
- Inside-casing gravel packing
- Open-hole gravel packing
- Propped fracturing, including frac-packing, gas propellant fracturing, and use of resin coated sand
- Selective perforating
- Production rate control

Table 4-1 is a critique of different mentioned methods used for dealing with sand production. Generally sand control represents high-cost, low-risk solutions. Sand management leads to low-cost solutions, but it also involves active risk management.

Table 4-1.Critique of different sand prevention methods [6]

Sand Control Method	***Major Short-Comings***
Screens. Slotted liners, special filters (including expandable screens)	• Lack of zonal isolation • High placement & workover costs • Longevity of devices • Plugging and sand screen collapse • Screen erosion • Potential damage during installation
Cased-hole gravel packing	• PIs reduction • Placement and workovers difficulties • High cost of installation • Positive skin development
Open-hole gravel packing	• PIs reduction • Complexity of operation • Necessity for extensive under-reaming in most cases • Costs of installation
Chemical consolidation	• Some permeability reduction • Placement and reliability issues • Short intervals only
Propped fracturing, including frac-packing, gas propellant fracturing, and use of resin coated sand	• Permeability recovery • Risks of tip-screenout during installation • Directional control and tortuosity issues (in inclined wells) • Fracture containment control

	- Proppant flow-back on production
Selective perforating	- Problematic in relatively homogenous formations - Need for formation strength data - Reduces inflow area
Production rate control	- Erosion of facilities - Sand monitoring required - Separation and disposal required - Potential for lost production

4.3.1 Formation grain size distribution

In addition to understanding the failure characteristics of the formation, core sample is also used for determining the grain size distribution. This information is used as a starting point for selecting different sand control types and for selecting the appropriate gravel and screen size.

Particle size or grain size refers to the diameter of a grain of granular material that can be separated into four different groups such as: Gravel, Sand, Silt and Clay (Figure 4-3).

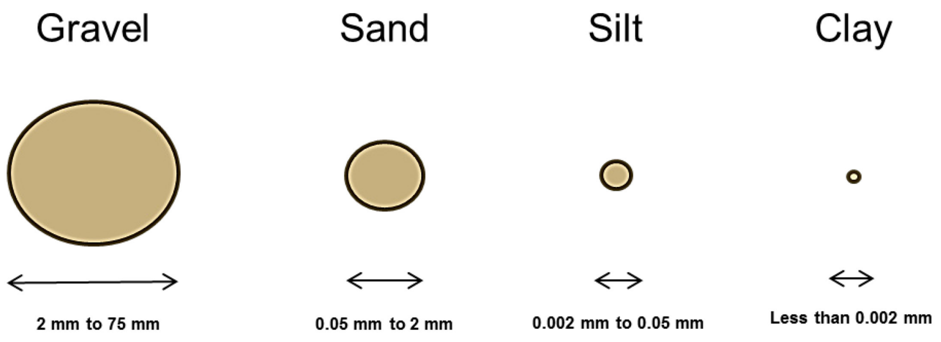


Figure 4-3 Gravel, Sand, Silt and Clay sizes

There is a wide range of instrumental and other methods of particle size analysis available. Some of the more common techniques are:

1. Sieve Analysis
2. Sedimentation Methods
3. Elutriation Techniques
4. Microscopic Sizing and Image Analysis
5. Electrical Impedance Method
6. Laser Diffraction Methods

Among all these techniques mentioned above there are only two techniques which are being used generally in oil and gas industry. These two techniques are: Sieve Analysis or known as

Dry sieving and Laser Particle Size (LPSA) analysis. Both techniques are widely used, but LPS has largely replaced traditional sieve analysis as it is quicker, cheaper, and more representative of the finer particles and requires a smaller sample. LPSA can be performed on samples as small as 1 g enabling it to be used on sidewall cores and cuttings (assuming that they remain representative of the reservoir formation). The small sample size used may make results non-representative, but this can be avoided by using more samples. Before either technique is used, the sample must be prepared in accordance with API-RP-58 as bellow [7]:

1. The core is cleaned so that the oil and brine are removed. Solvents such as methanol and chloroform are used with additives to prevent damage to clay minerals. This process can take several weeks with heavy oil reservoirs.
2. The core is slowly being dried to prevent damage to clay minerals.
3. The core is broken up using a pestle and mortar. Care must be taken not to grind or crush grains and this can be confirmed by using a microscope. The microscope will also confirm when the disaggregation is complete. [7] [3]

4.3.1.1 Dry Sieving Analysis (DSA)

In this method the sample must be cleaned, crushed, dried, weighed, and then sorted using multiple sieves with openings in accordance with ASTM E11-13 [8]. The weight of sand in each sieve is recorded, all the way down to No. 325 mesh (Appendix-A). The overall weight percent of each saved sample is then plotted against the sieve aperture on semi-log coordinated to achieve a size distribution plot. For using this test some consideration must be noted as below:

- A sample size greater than 10g is required for a representative test.
- Its lower measures are according to No. 325 mesh (44µm).
- A good dispersion is hard to obtain.

Figure 4-4.Dry sieve device [9]

4.3.1.2 Laser Particle Size Analysis (LPSA)

The logic behind this method is that the diffraction angle of light striking a particle is inversely proportional to the particle size. The sand sample is placed inside the unit and the light diffraction caused by all the particles is measured, in turn concluding the size of individual particles. The unit is integrated with a computer which allows for an automated process. Analysis software will record and plot the grain-size distribution. In this method for a representative test a smaller sand sample is required than dry sieving method. LPSA can measure sands down to 4µm.

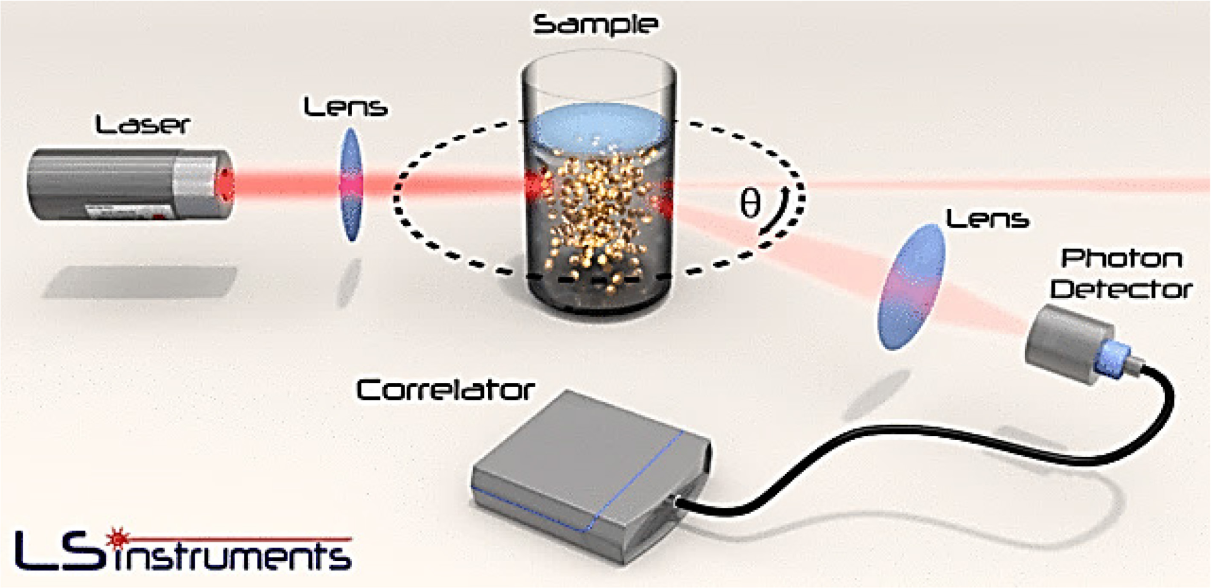


Figure 4-5 Laser Particle Size distribution process [10]

Figure 4-6 shows the difference between two LPSA and Dry Sieving methods. Percentile sand sizes can be obtained from the cumulative distribution where, for instance, the D10 value is the grain-size diameter from the distribution scale where 10% by weight of the sand is of a larger size and 90% is of a smaller size. Reading the graph (Figure 4-7) at the 50% cumulative weight provides the median formation grain-size diameter.

The grain-size distribution analysis plot establishes the degree of sorting in a particular sample. A near vertical analysis plot represents a high degree of sorting or uniformity. A more deviated or slanted plot indicates poor sorting of sand grains (Figure 4-7).

Uniformity coefficient (UC) expresses the distribution uniformity by the ratio of the diameter at 40% point to the diameter at the 90% point:

$$UC = \frac{d_{40}}{d_{90}} \qquad [11](Eq.\ 1)$$

Perfectly uniform sample would have a sorting and UC of 1. For UC less than 3 we have uniform sands, for UC between 5 and 10 we have non-uniform sands and for UC more than 10 we will have extremely non-uniform sands [11].

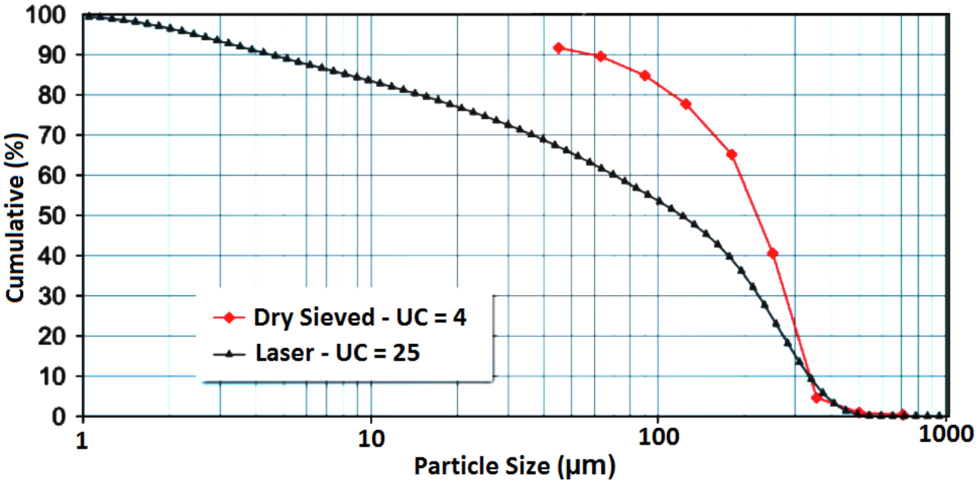


Figure 4-6 LPSA versus DSA [12]

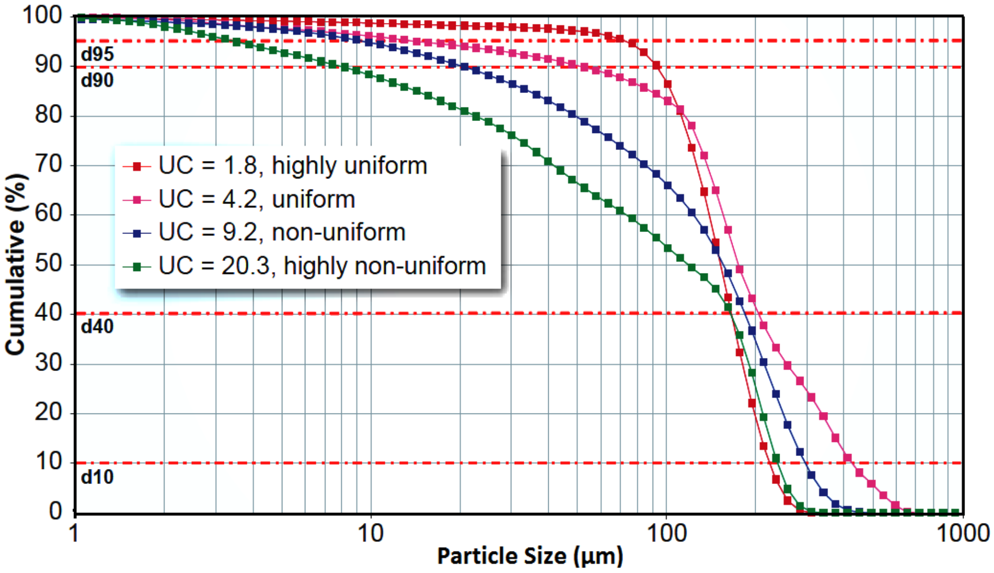


Figure 4-7 Uniformity Coefficient Examples [12]

4.3.2 Sand Control Screens and Slotted liners

There are different types of sand screens commercially available in oil and gas industry. These screens can be separated into three main groups as: 1. Wire-wrapped screens (WWS) 2. Pre-packed screens (PPS) 3. Premium screens (also called Mesh or Woven screens).

ISO 17824:2009 Standard provides the requirements and guidelines for sand control screens for use in the petroleum industry. It covers the requirements for design, design validation, functional evaluation, manufacturing, storage and transport. It includes test methods to determine when wire-wrap, pre-pack and metal-mesh screens lose sand control when subjected to a hydraulic collapse or burst load. [13]

In addition to sand screens, slotted liners are also used for sand control, although it is difficult to make the slots small enough to stop anything but the coarsest of formations. A saw can cut slots down to around 0.025 in. whilst a laser can be used to cut finer slots this process is also called as laser cutting. The slots are longitudinal. Even with suitably sized slots, either the strength of the liner or the flow area through the slots is severely restricted (typical flow area 2–3%). Tensile strength is not severely affected by the slots, but compressional strength will be as rigidity is reduced. Compressional and torque rating is improved by offsetting the slots [14].Great care may be required if they need to be pushed to the bottom of the well. They do have the advantage of being the cheapest screen type. Slotted liners can be divided into four different groups regarding the distributions types. In Figure 4-8 you can see the different types of slotted liners.

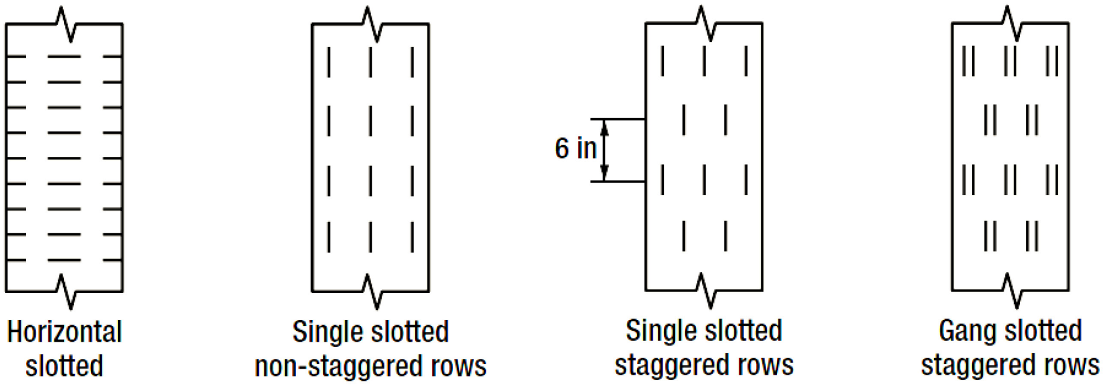


Figure 4-8 Slotted-liner geometry [6]

Slotted liners are the cheapest form of sand control but they can be easily plugged, they have a smaller inflow area compared to other sand screens, they have higher pressure drops through production than the regular sand screens and the same bridging theory is applied for them like for sand screens. Regarding the design of the slots there are two common types of design which are used in the industry, straight shaped slots versus keystone shaped. The main difference is the less chance of plugging for keystone shaped in comparison with straight shaped as they are illustrated in Figure 4-9 and Figure 4-10.

Figure 4-9 Keystone shaped slots

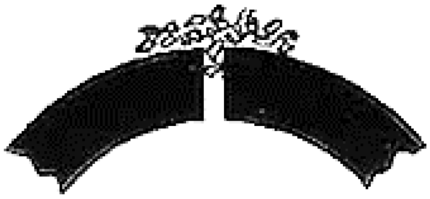


Figure 4-10 Straight shaped slots

All forms of screen can be run in either a cased hole or open hole well with or without gravel packing, although each will have its optimum environment. Screens can also be run into open holes with a pre-installed or pre-drilled liner to provide additional installation protection.

4.3.2.1 Wire-wrapped Screens (WWS)

The wire-wrapped screens are normally used in gravel pack and standalone completions; they comprise a base pipe with holes or in another word slotted liners, longitudinal rods and a single wedge-shaped wire wrapped and spot-welded to the rods (Figure 4-11). Some designs omit the longitudinal rods, but they do help offset the wire wrap from the pre-drilled base pipe holes. The wire is either welded or gripped by a connector at the ends of the screen.

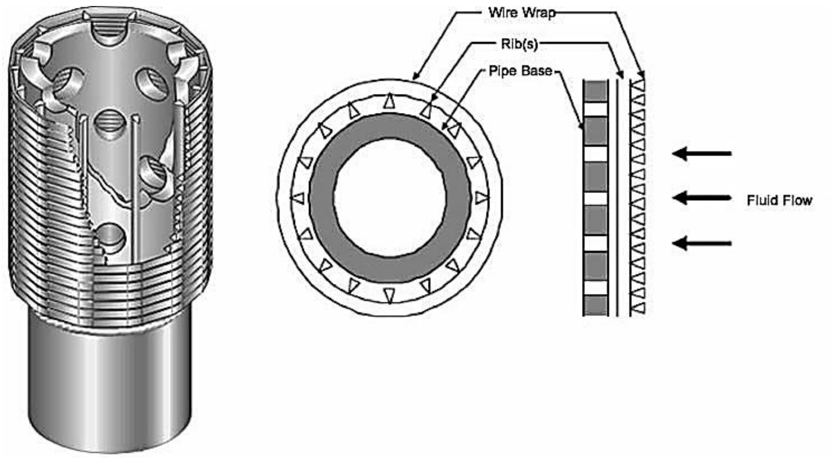


Figure 4-11 Wire-wrapped screen

The keystone (wedge) shape of the wire ensures that particles bridge off against the wire or pass right through and are produced. This provides a degree of self-cleaning, but wire-wrapped screens still have a relatively low inflow area. The inflow area will depend on the wire thickness, the slot width and the percentage of screen joint that comprises slots (as opposed to the connections). In Figure 4-12, for example using the Coberly criteria for slot sizing (2 X D10), the screen inflow areas are calculated for a variety of formation grain sizes and two sizes of wire (0.047 in. and 0.09 in.). It is assumed that 90% of the screen joint length comprises slots.

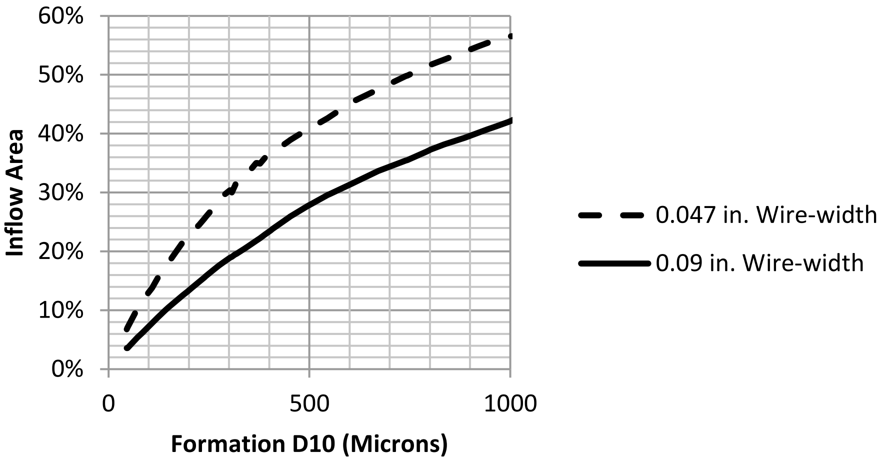


Figure 4-12 Examples of wire-wrapped screen inflow area [3]

Note that if the more conservative 1 X D10 criteria is used, then the inflow area reduces by nearly 50%. Even an inflow area of 5% is more than sufficient if the screens do not plug. Such an area is substantially more than the flow area of a cased and perforated well. For gravel pack completions, the wire wrapped screen stops the gravel and fine material will either be stopped by the gravel or be produced through the screens.

The materials which are being used for fabrication of wire-wrapped screens are usually made of 316L or Alloy 825 (Nickel alloy) which later on chapter 5 of this thesis will be fully discussed in terms of whether they can be used in sever situations like sweet and sour environments or not. Like all types of screens, acidisation, other chemical treatments and corrosion can be damaging to the small cross-sectional area of the wire The base pipe will normally be the same metallurgy as the tubing (e.g. 13Cr). Base pipe failures are rare, but collapse failures have been reported when the screen has plugged up. [3]

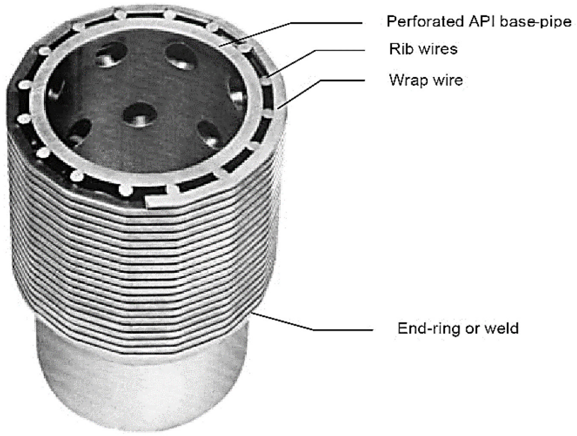


Figure 4-13 Wire-wrapped screen

According to ISO 17824:2009 standard two common types of wire-wrap screens are direct-wrap and slip-on and the differences in the products are shown in Figure 4-14 [13]

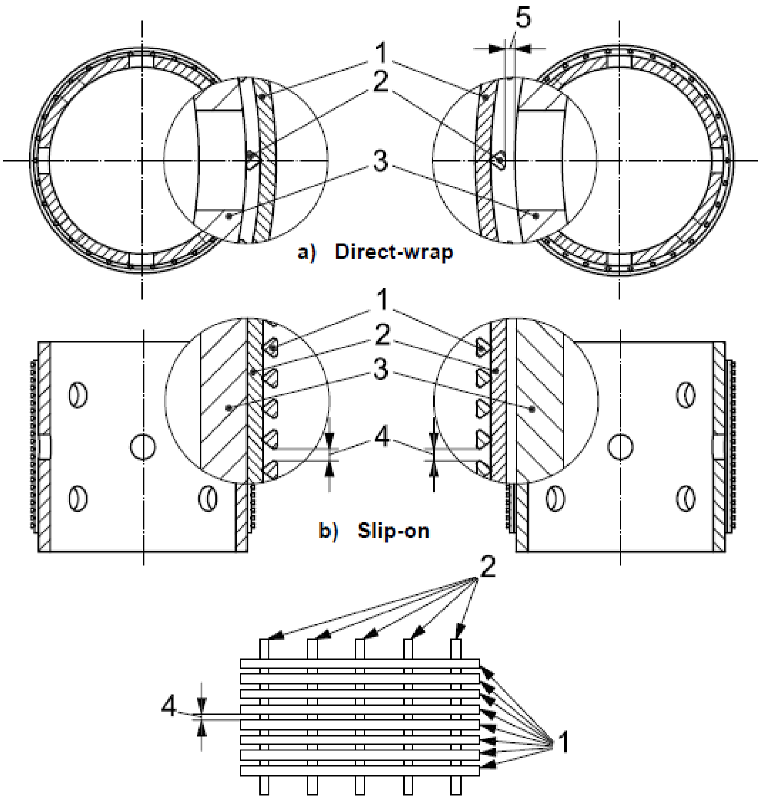


Figure 4-14 Wire-wrap screen illustrations [13]

Where: 1. Wrap-wire 2. Support rib 3. Basepipe 4. Slot 5. Support rib to base pipe clearance.

4.3.2.2 Pre-packed Screens (PPS)

The pre-packed screens are modified version of wire-wrapped screens and basically there are three types of them, dual-screen pre-packed, single screen pre-packed and slim-packed as shown in Figure 4-15. They are being used in different situations and conditions.

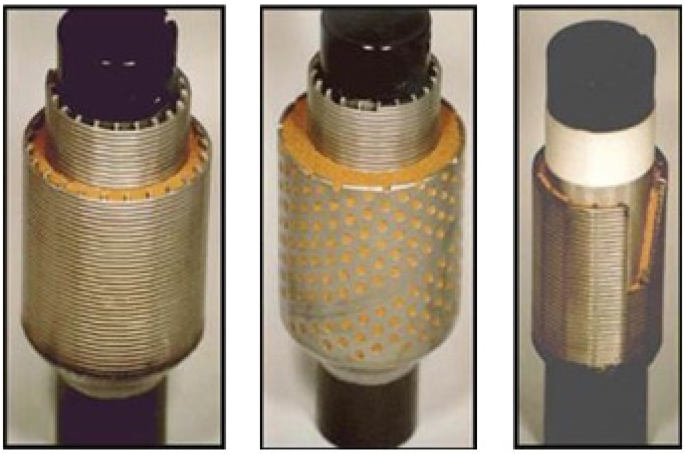


Figure 4-15 LR: Dual-screen pre-packed, Single-screen pre-packed and Slim-packed [6]

They are constructed in a similar way like wire-wrapped screens, but with two screens. The screen slots are sized to prevent the escape of gravel packed between the screens as it is shown in Figure 4-16 and Figure 4-17. The gravel is usually consolidated to limit the potential for a void to develop. It is tempting to consider pre-packed screens as a pre-built gravel pack. They are not. The fundamental advantage of gravel packs is that they remove the annulus between the screen and formation and thus prevent sand failure and sand transport. A pre-packed screen does neither of these. They do however offer a degree of depth filtration, and the relatively high porosity (over 30%) combined with their very high permeability's provide minimal pressure drops [15]. Pre-packed screens can be prone to plugging and are no better at resisting jetting of sand than wire-wrapped screens.

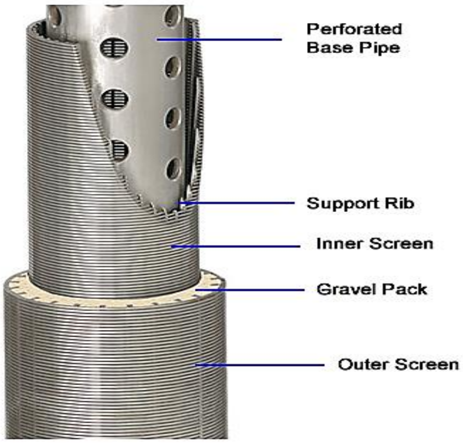


Figure 4-16 Pre-packed screens [16]

The equivalent inflow area for a pre-packed screen can be less than 5%. There has been a concern that acid can damage the resin in the pre-pack, although this is refuted by tests [17]. To provide some installation protection and jetting resistance, pre-packed screens can incorporate an outer shroud, though this will increase the thickness. Premium screens or the simpler wire-wrapped screens have now largely replaced pre-packed screens, but pre-packed screens still remain in popular use in some areas of the world.

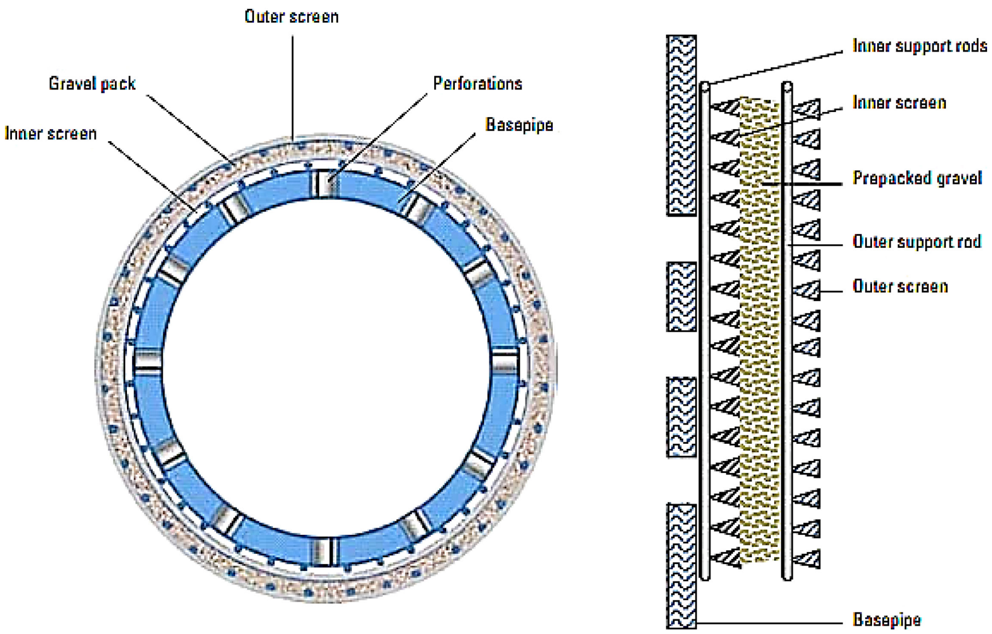


Figure 4-17 Pre-packed screen vertical view and side view [18]

The materials which are being used in the industry for fabrication of pre-packed screens are usually made from stainless steel 304, 316L. Pre-packed screens can also be customized to catch up with special requirements with the help of more advanced materials such as 625, 825 and C276 to fulfill the needs which later on chapter 5 of this master thesis are going to be discussed in details.

According to ISO 17824:2009 standard two common types of pre-packed screens are direct-wrap and slip-on and the differences in the products are shown in Figure 4-18

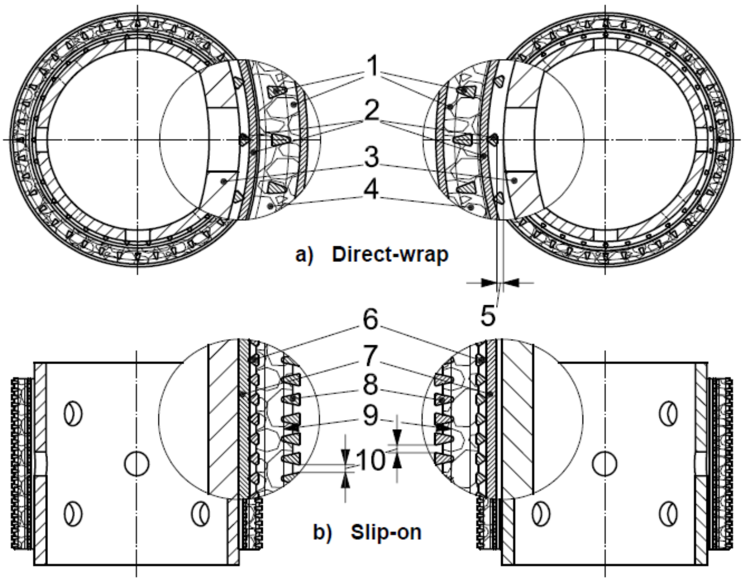


Figure 4-18 Pre-packed screen illustrations [13]

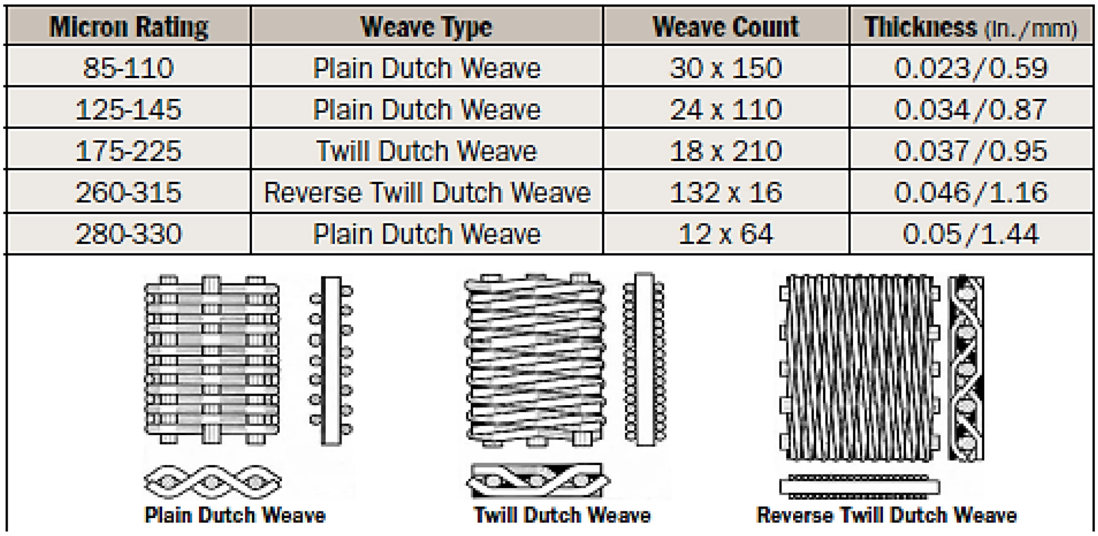
Where: 1. Outer screen jacket 2. Inner screen jacket 3. Basepipe 4. Sand or synthetic proppant 5. Support rib to base pipe clearance 6. Inner screen jacket wrap-wire 7. Inner screen jacket support rib 8. Outer screen jacket wrap-wire 9. Outer screen jacket support rib 10. Slot.

4.3.2.3 Premium Screens

Premium screens or Metal-mesh screens, as they are shown below in Figure 4-19, are one of the most expensive sand control methods comprising of different non pre-packed sand excluding sintered woven wire layers around the perforated inner pipe. Some of the layers are used for sand filtration while others are used for the fluid drainage or interior protection. Although the outer screen layers are also used as filtering fronts, their primary task is to protect the inner layers from possible damage occurrence [6]. Sintering the wire provides better mechanical properties of the screen making it a robust device capable of withstanding the highest pressures and inflow rates. Wire weave pattern can be either Dutch weave or square weave depending on desired slot size. They are shown below in Figure 4-20.

Loads distributing through downhole equipment affect only the inner pipe so the rest of the screen parts are left unstressed. Moreover, premium screen protective layers and wire layers are thicker and stronger than the other screen types which make them very enduring [3]. There are three different types of premium screens: 1. Sintered metal screen, 2. Strata pack screen and 3. Excluder screen.

Figure 4-19 LTR: Sintered Metal Screen, Strata pack Screen, and Excluder Screen



Micron Rating	Weave Type	Weave Count	Thickness (In./mm)
85-110	Plain Dutch Weave	30 x 150	0.023/0.59
125-145	Plain Dutch Weave	24 x 110	0.034/0.87
175-225	Twill Dutch Weave	18 x 210	0.037/0.95
260-315	Reverse Twill Dutch Weave	132 x 16	0.046/1.16
280-330	Plain Dutch Weave	12 x 64	0.05/1.44

Figure 4-20 Wire weave patterns and sizes [19]

Notes for wire weave patterns: 1. Plain Dutch Weave: Woven in plain over under pattern of weft wires (warp wires are typically heavier and larger in diameter than weft wires). 2. Twill Weave: similar to Plain Dutch Weave except woven in a twill style over 2 wires and under 2 wires. 3. Reverse Weave: warp and weft wires are reversed.

The materials which are being used in the industry for fabricating the pre-packed screens are usually made of stainless steel 304, 316L, Alloy20. Premium screens like other types of sand screens can also be customized to catch up with special requirements with the help of more advanced materials such as 625, 825 and C276 to fulfill the needs which later on chapter 5 of this master thesis are going to be discussed in details.

According to ISO 17824:2009 standard two common types of metal-mesh screens are an inline design with a series of round holes in the protective shroud or an offset design with narrow slotted openings and the differences in the products are shown in Figure 4-21 [13].

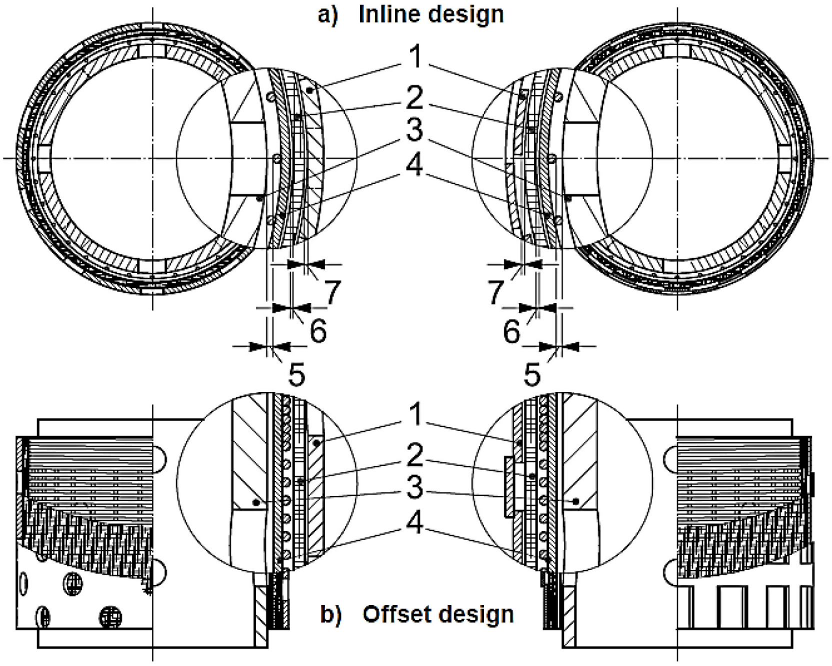


Figure 4-21 Metal-mesh screen illustrations [13]

Where: 1. Shroud 2. Metal-mesh media 3. Base pipe 4. Drainage or support layer 5. Clearance between drainage and base pipe 6. Clearance between mesh and drainage layer 7. Clearance between shroud and mesh. [13]

Schlumberger premium screens are designed for Open-hole completions with or without a gravel-pack and the filter cartridge is available in 316L stainless steel or Alloy 825 material. Specifications of these types are in Appendix-B [20].

4.3.2.4 Expandable Sand Screens (ESS)

ESS is a technology concept which was envisaged by Shell and was developed initially by Petroline. ESS was first trialed in 1997 (in Oman Q1) with the idea that eliminating the annulus between the sand screen and wellbore would improve downhole sand control and allow enhanced reservoir performance and management [21]. Expandable sand screens are a globally accepted sand control system with more than 677 installations worldwide across all vendors by the end of 2012 [21]. A growing body of data suggests that when compliantly expanded in open-hole they perform very well, with consistently low skins and high PIs. Where comparisons have been done, the expandable screens perform at least as well as other sand exclusion systems such as standalone screens and open-hole gravel packs. There are a number of possible reasons for the high performance:

1) The ESS presents a large open area to the formation. This gives a low pressure drop across the screen and minimizes the possibility of plugging to a minimum.

2) The compliant expansion into contact with the wellbore limits the zone of deformation around the hole.

3) Compliance also improves filter cake clean up by reducing mixing with failed sand [22].

The slim nature of the design facilitates deployment of the screens in various open-hole applications, including high dogleg severity and horizontal wells. After deployment, the ESS can be expanded by a solid expansion cone and/or an Axial Compliant Expansion System. Once ESS is expanded it virtually eliminates the annulus, making gravel packing operations unnecessary in reservoirs that carry risks such as reactive shale, low fracture gradient, fractures or faults. A partially expanded ESS is illustrated in Figure 4-22.

Figure 4-22 A partially expanded ESS

ESS consists of three layers: (1) a slotted base pipe, (2) a filtration medium (Petroweave) and (3) an outer protective shroud (Figure 4-23).

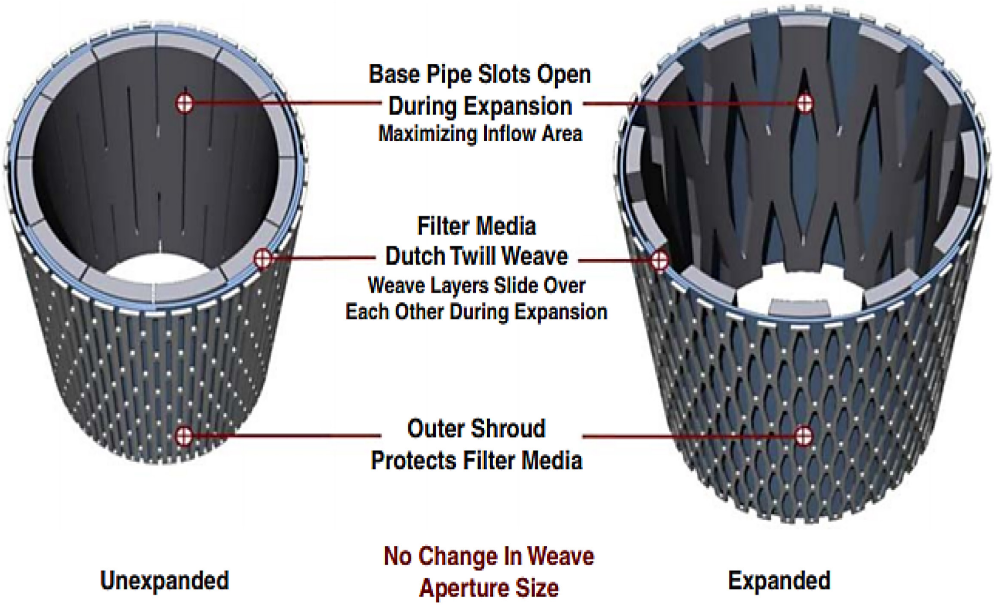


Figure 4-23 ESS construction [21]

From inception to the end of 2012, ESS has been used to complete 677 wells with 418,184ft of screen length installed. Figure 4-24 details the installations of ESS by completion type. As it can be observed on the left hand side, 451 installations, representing 67% of all wells, have been completed in an open-hole environment. With regard to cased-hole applications, this accounts for 193 installations, 28%, with open perforations and 33 installations, 5%, with either pre-packed or frac-packed perforations. Figure 4-24 (right hand side) details a more extensive open-hole application of the technology in terms of footage: 355,877ft or 85% of total screen length installed has been in an open-hole environment. As such, cased-hole applications represent 52,23ft or 13% with open perforations, and a further 10,077ft or 2% with either prepacked or frac-packed perforations. [21]

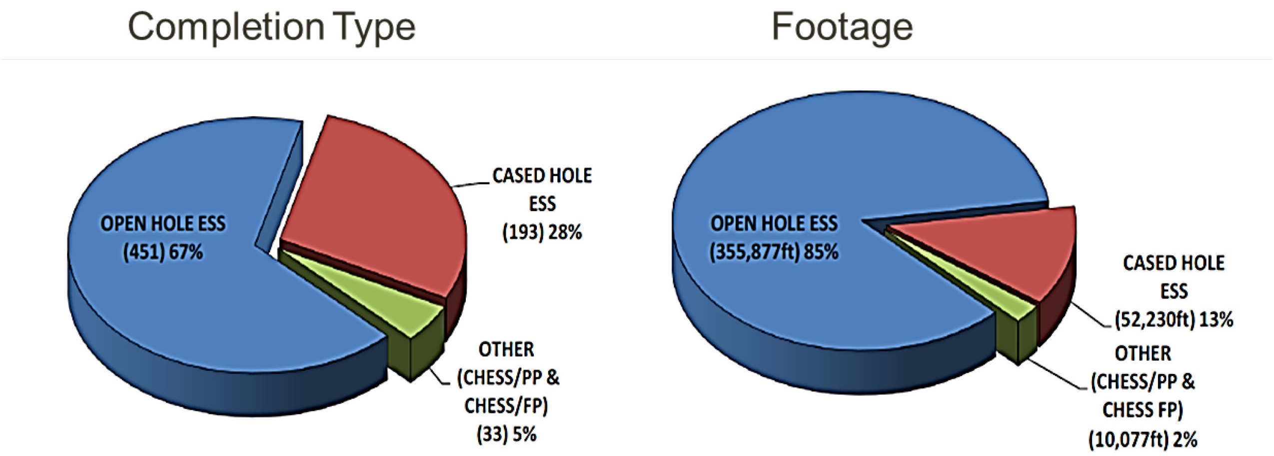


Figure 4-24 ESS installations by completion type and footage [21]

In 2005, the 7 inch ESS system was introduced. Developed in collaboration with an operator to meet industry needs, the system was specifically tailored for $8^1/_2$ in. open-hole, multi-zone applications. This involved integrating open-hole isolation devices, in addition to improved collapse strength and increased compliant range in comparison with the $5^1/_2$ inch ESS system. There are various open-hole isolation options that are compatible with 7 inch ESS. These include expandable zonal isolation, mechanical zonal isolation, and swelling-elastomer technology. Together, the 7 inch ESS system enables open-hole productivity with cased-hole functionality. Table 4-2 outlines details of current ESS systems.

Table 4-2 Current ESS systems [21]

Size (in.)	Hole Size (in.)	Run Outside Diameter (in.)	Maximum Compliant Diameter (in.)	Expansion Type	Filter Media
4.0	5.88	4.40	6.06	• Axial-compliant expansion • Expandable connections	Dutch twill • 120µm • 150µm • 230µm • 270µm
4.5	6.0	5.0	6.75		
5.5	8.5	6.1	8.83		
7.0	8.5	7.6	9.25	• Rotary-compliant expansion • Premium connections	

Figure 4-25 shows the 351 current ESS open-hole installations by application. Oil-producer wells account for 215 installations, or 61%. Gas-producer wells account for 81 installations, or 23%, the earliest of which dates back to Q1 2001. Water-injector wells account for 48 installations, or 14%, the earliest of which dates back to Q4 2002. Other wells, including gas-storage and water producers, account for a further seven installations, or 2%.

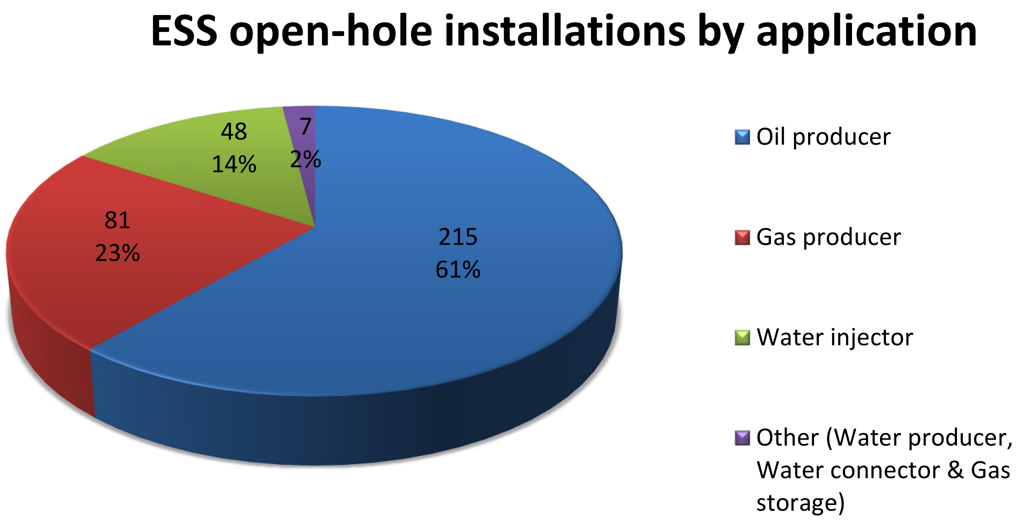


Figure 4-25 Current ESS open-hole installations by application

Some key features of ESS are: 1. They are being used mainly in oil producers, gas producers and water injectors wells. 2. The wells producing for more than 13 years. 3. They have maximum production rate of 30,000stb/day. 4. Maximum gas rate of 370 MMscf/day. 5. Maximum water injection rate of 65,000 bwpd. 6. Mainly used in deep water application 7. They can be used in both single and multi-zone areas. 8. They are used only in deviated and horizontal wells. [21]

4.3.2.5 Sand Screens Common Problems

Problems with screens generally develop under two conditions: during completion or production. Some of the problems encountered with screens during completion operations are: erosion-corrosion, collapse, plugging and wrap failure. During the production phase, only two problems, which are erosion (leading to sand production) or plugging (leading to production decline), are generally encountered. [23]

4.3.2.5.1 Erosive failure of screen

Erosive failure results in formation of holes such as those shown in Figure 4-26. These holes somewhat resemble the ones resulting from pitting corrosion; however, a closer examination reveals the distinctly different features of the erosion holes which do not include any surface pitting.

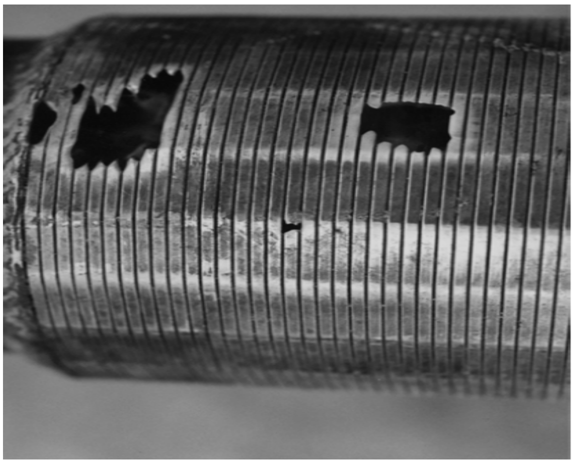


Figure 4-26 Erosive failure of a wire-wrapped screen [23]

4.3.2.5.2 Screen collapse

Collapse of screen occurs from application of differential pressures (across the screens) that exceed the collapse strength of the screen jacket. The resulting failure may not always be critical. But, in general, screen jacket collapse may lead to subsequent long term erosive failure. Typically, prepacked screens have higher collapse strengths than the wire-wrapped screens of comparable size. Figure 4-27 shows a cross-section of a collapsed screen jacket.

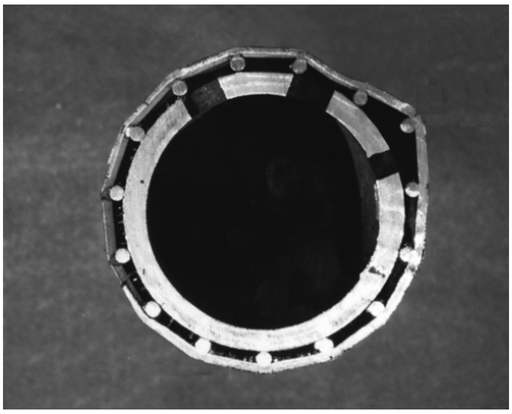


Figure 4-27 Collapse failure of a wire-wrapped screen jacket [23]

4.3.2.5.3 Screen plugging

Plugging of a screen may occur as a result of formation fines migration into a wellbore. These fine solids flow through the throat of the gravel pack surrounding (in case of using gravel packing method) the screen and into the screen openings causing partial plugging. As production continues, these fine solids will bridge against the screen and eventually plug the screen [24]. Plugging happens during completion, although not very common, can occur due to a variety of reasons such as incompatibility of completion and formation fluids, premature accidental production of fines through the screen prior to cleanup, or injection of debris-laden and unfiltered fluids through the screen. In some cases, the screens can be cleaned in place chemically through acidizing or mechanically through back-washing. However, in the majority of instances, screens are pulled out of the hole and cleaned at the surface. Screen plugging during production is usually expected to be the result of formation fines but sometimes damage resulting from muds and completion fluids could also lead to screen plugging [23].

4.3.2.5.4 Wrap Failure

Wire failure is a rare occurrence. It is due to deficiency in strength of weld between the wire wrap and the ribs. Figure 4-28 shows a failed wrap on a screen. Proprietary weld strength measuring systems have been developed, which allow control of the welding process through load and current modulation, and lead to excellent weld quality. Another potential source of wrap failure is during bend negotiation in a short radius well. This is due to the drag forces imposed on the outer surface of a screen during installation. Bending tests may be conducted in the laboratory to verify the adequacy of the weld strength to provide the needed mechanical integrity of the wrap. [23]

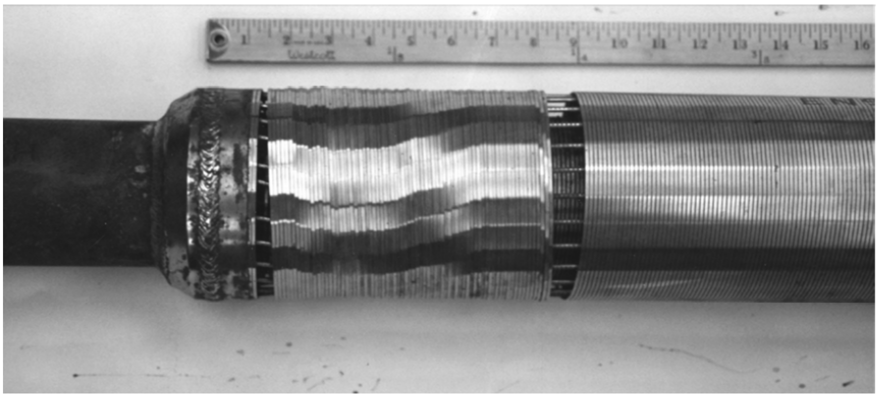


Figure 4-28 Screen wire-wrapped failure [23]

4.3.3 Sand Control Gravel Packs

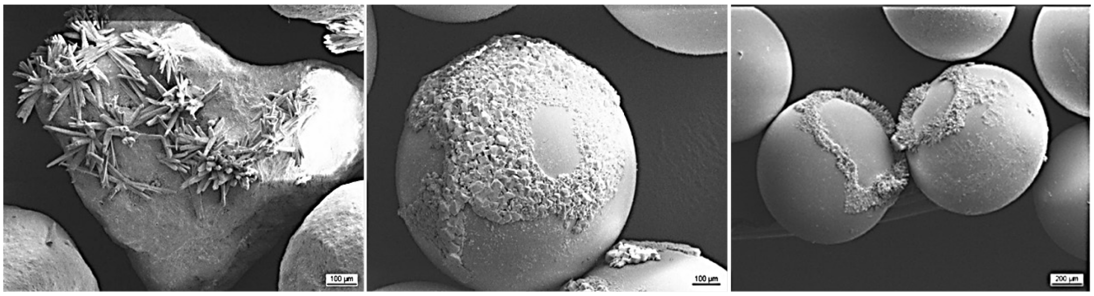
This type of sand control system deploys sand screens such as wire-wrap or metal-mesh (Premium) plus gravels to be filled around these screens. The screen is placed in the wellbore and the surrounding annulus is packed with gravel of a specific size to retain the formation sand. Gravel pack is the most efficient and trusted method of sand control. There are basically three types of gravel packs which are being used in the industry: 1. Open Hole Gravel Packs (OHGP) 2. Cased Hole Gravel Packs (CHGP) 3. Frack Packs

4.3.3.1 Gravel Selection

Gravels can be separated into different types regarding the materials such as:

- Sands
- Bauxite
- Resin-coated proppants
- Pre-coated gravel
- Ceramics
- Glass Beads
- Hydrophobic Glass Beads [25]

Rounder the proppants are better the permeability is, and this can only happen by replacing the conventional proppant such as sand with glass beads or ceramics. Figure 4-29 shows the microscopic difference between ceramics, normal glass beads and hydrophobic glass beads and Figure 4-30 shows the permeability evaluation between these types.



Ceramic **Glass** **Hydrophobic Glass**

Figure 4-29 Microscopic evaluation after static test on different gravels [25]

As it is shown in Figure 4-29 from scaling point of view, hydrophobic glass beads have the least amount of precipitation and regarding the sphericity, glass beads have the most spherical shape which must be considered to be used instead of conventional gravels.

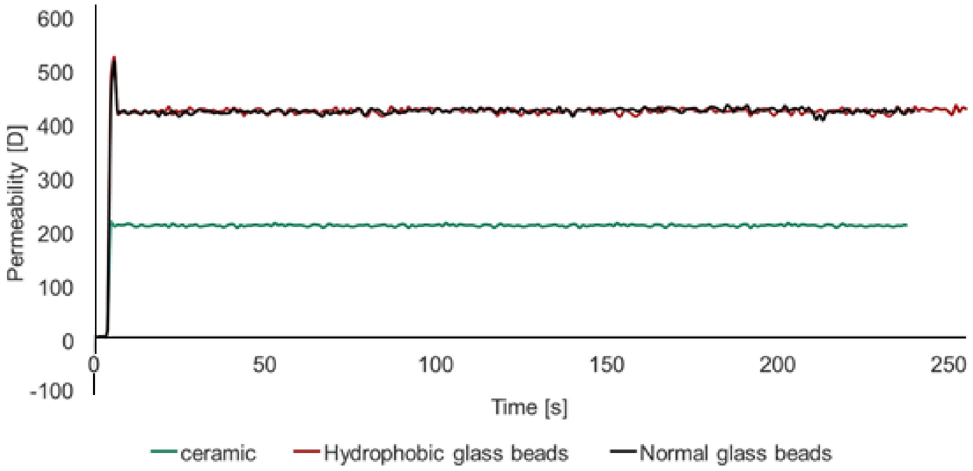


Figure 4-30 Evaluation of permeability in glass beads and ceramics [25]

There is a proposed criteria by Tiffin, [26] based on the field experience conducted with core samples from different formations which can be used in order to distinguish which types of screens to use [26]:

- Standalone screens can be used if $d_{10}/d_{95} < 10$.
- Wire-wrapped screens should be used if $d_{10}/d_{95} < 10$ and $d_{40}/d_{90} < 3$ and fines < 2% by weight.
- Woven mesh screens should be used if $d_{10}/d_{95} < 10$ and $d_{40}/d_{90} < 5$ and fines < 5% by weight.
- Large gravel ($7\text{-}8 \times d_{50}$) should be used if $d_{10}/d_{95} < 20$ and $d_{40}/d_{90} < 5$ and fines < 5% by weight.
- When $d_{10}/d_{95} < 20$ and $d_{40}/d_{90} < 5$ and fines < 10% by weight it is advisable to use a combination of larger gravel and fine-passing screen.

- With large amount of fines ($d_{10}/d_{95} < 20$ and $d_{40}/d_{90} < 5$ and fines > 10% by weight) there is a need for enlarging wellbore (it means to move the gravel or formation sand interface away from the wellbore).

4.3.3.2 Open-Hole Gravel Packs (OHGP)

They are originally used in vertical and deviated wells, from the middle of 1990s; OHGP became a common form of sand control; particularly in horizontal wells, where they can be very productive. The intention is simple; pack the annular space with gravel sized to stop formation sand from being produced and size the screen to prevent the gravel from escaping. When successfully installed, they prevent the formation from collapsing and therefore reduce fines production, but the filter cake (if still present) must flow back through the gravel and screen. Operationally, they can be challenging (particularly with respect to fluid selection and deployment), and like all forms of sand control, success is not guaranteed. A gravel pack must be designed. There are two main forms of OHGP are in common use: circulating packs and alternate path or shunt tubes. The summary of circulating packing versus alternate path is found in Table 4-3. Each technique can be used in conjunction with pre-packed, wire-wrapped or premium screens.

Correct sizing of Gravel packs for sand retention in Gravel Pack and Frac Pack completions has been a controversial topic for many years dating back to the 1960's. One of the earliest studies completed, and still often cited, was by Saucier in 1974. Saucier proposed sizing the gravel based on the median size of the formation multiply by six (d50 * 6) [27]. The Saucier criterion is still often used and works well for many applications. In 1998, Tiffin furthered the Saucier work in and suggested that for some specific formation sands, the gravel could be size as much as 7–8 times the median size of the formation [26]. In both bodies of work, the median size of the formation is really the only formation size parameter that is considered in the gravel pack size selection. [28]

Table 4-3 Circulating OHGP versus alternate path

	Alternate Path	**Circulating Pack**
Gravel pack fluids	Water (or oil) with viscosifiers. Viscous fluids may not clean up and require more quality control	Water used with friction reducers and additives
Slurry density	Higher concentrations: around 8ppa	Typically 0.5-2ppa
Fluid volume and time	Higher slurry concentrations require lower fluid volumes and reduced pumping times	Correspondingly larger fluid volumes as gravel concentration is reduced
Fluid loss	Complete returns not needed. Possible without any returns	Poor returns will lead to premature screen out and incomplete pack

Pressure	Can exceed fracture pressure	Must not exceed fracture initiation pressure
Hole condition	Less critical	Critical washouts or previous casing rat hole may cause
Filter cake removal	Low consequences and can be encouraged. May not need separate circulation and spotting of breakers	If filter cake removed, can screen out due to losses. Filter cake removed after gravel packing
Screen size	Smaller base pipe screen, but larger overall diameter to accommodate shunts	Larger base pipe screens possible for a given hole size
Cost	Less time, but more (and expensive) chemicals	More rig time for pumping

4.3.3.3 Cased-Hole Gravel Packs (CHGP)

CHGP or cased-hole gravel packs and particularly their extension to frac packing are extensively used in the Gulf of Mexico and sometimes other places. In some environments, like the North Sea, they are rarely used. They provide the most reliable sand control completions [29] particularly in environments where other sand exclusion techniques struggle (laminated shale and sand intervals, lower permeability formations and high fines contents). They also offer the opportunity for zonal isolation by the use of stacked packs. The downside is significant operational complexity, logistics and time. The cost and complexity makes them considerably less attractive (but not impossible) for long reservoir sections. They become increasing less suited for higher permeability formations as productivity declines. The basic typical steps in a cased-hole gravel pack are [3]:

- Perforate the casing/liner and possibly clean up the perforations and associated debris.
- Run a sump packer to isolate the stagnant volume below the perforations and provide a latching point for the screens.
- Run the screens and gravel pack packer with a crossover tool.
- Pack the annulus by a combination of squeezing and possibly circulation. Packing may be performed above or below fracture pressure. If a frac pack is required, a TSO fracture design is used.
- The gravel pack ports in the packer are isolated and excess proppant is reverse circulated out through the running string.

The desired final result is that the annulus and the perforations are tightly packed with gravel so that they can filter out the formation sands. Figure 4-31 is showing OHGP and CHGP.

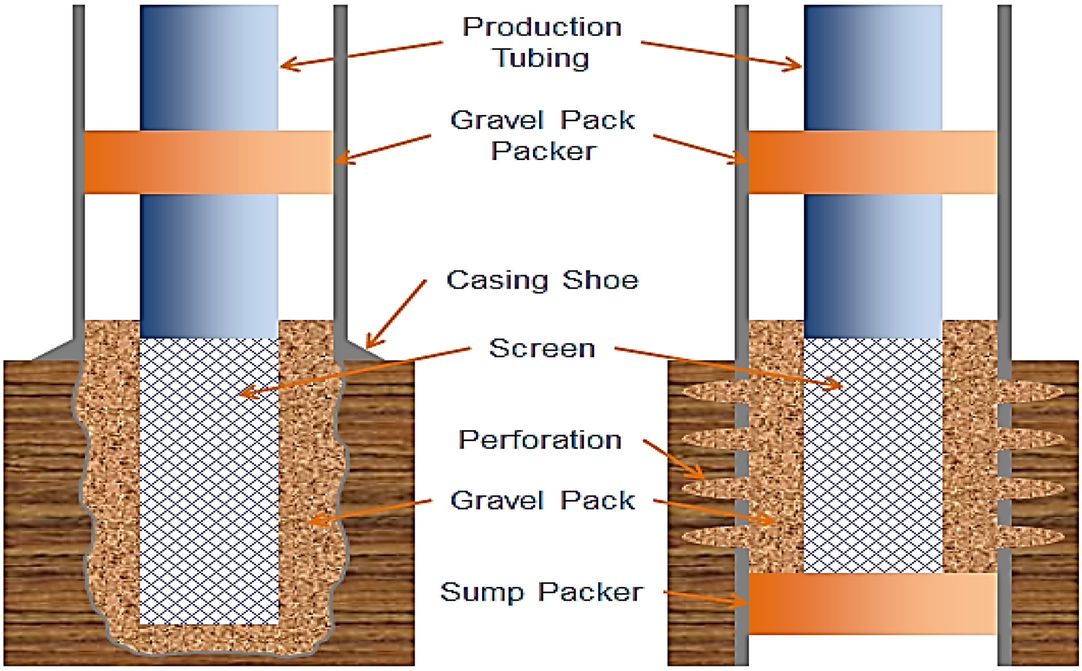


Figure 4-31 OHGP (Left) and CHGP (Right)

4.3.3.4 Frack Packs

This method was developed at the end of 1980s after TSO fracturing techniques had been developed for Prudhoe Bay (Alaska) and the North Sea. The term ‘frac pack’ however dates back to the 1950s when Shell fractured and then gravel packed wells in Germany [30].

In comparison to CHGP, frac packs require: 1. more complex fluids 2. larger volumes 3. higher pump rates, plus the associated mixing and pumping equipment. However, in areas such as the Gulf of Mexico and Brazil where such equipment is readily available, usually with the help of dedicated fracture stimulation vessels, the additional cost is small in comparison to the benefit. As a result, frac packs have become the cased-hole sand control technique of choice in these areas and is overall the most common form of cased-hole sand control. In places where fracture stimulation vessels are unavailable, large skid-mounted pumps and continuous mix equipment is increasingly used, for example, offshore India in the South Tapti field where frac packing up to 30 bpm is reported. Occasionally, this equipment has been mounted on supply vessels to avoid deck space constraints. [3]

5 Corrosion

5.1 Introduction

As a phenomenon, corrosion results in hefty costs annually with billions of dollars at loss. According to a report published by U.S government, the total cost of corrosion in upstream operations and pipelines is estimated to be $1372 billion annually, with the lion share of the costs going to pipelines. Downhole tubing and a rise in capital expenditures (e.g. CRAs, etc.) occupy the second and third places, respectively. Preventing the occurrence of those failures that result in reduced production can provide the best opportunity for saving [31]. Moreover, the reduction of the maintenance budget cannot be justified by the disappearance of corrosion in the systems. This recognizes the fact that due to the ageing feature of the oil fields, they are subject to more corrosions and this will result in reduced return on investment. It is estimated that corrosion costs are estimated to be tantamount to the cost inflicted by mechanical breakdowns in maintenance.

Due to its complicated and intricate production techniques as well as the potential environmental hazardous, the oil industry needs to take in a bigger than average share of these costs. All components at any life stage of an oil and gas field can be potentially subject to corrosion i.e. the deterioration of a metal or its properties. Corrosion can inflict damage in all parts and components (e.g. from early stages of oil exploration through drilling and abandonment). thus, researching new ways to fight such an adversary deserves to be devoted whatever high ethnology and research it needs [32].

The producing formation normally doesn't consist of ay oxygen which has an essential role in corrosion. The only stage where oxygen is present is the drilling activity in which the fluids containing oxygen are introduced. The well casing as well as equipment used for drilling, pipelines and mud handling machineries would be corroded by untreated drilling muds. Moreover, the completion strings can be intensely corroded under the influence of water and carbon dioxide (CO_2) that are used for secondary recovery or EOR. The metals can be attacked and corroded by acids which are used to decrease the formation damage as well as to clear the scales. The formations which can yield some sand particles along with high production velocity can corrode the pipelines on the ground surface. As another example of this type of damage, sand screens are corroded and eroded due to sand production and being located in corrosive environments. Yet another problem is posed by Hydrogen sulfide (H_2S). Dealing with such a diverse and complicated context of corrosion along with other complications (e.g. high temperatures, high pressures and enormous stress related to drilling or production) entails using the expertise of a corrosion engineer whose role in gas and oil industry is becoming increasingly important more than ever. Consequently, the various solutions proposed by corrosion engineers for corrosion prevention are assessed in terms of both cost and benefits [32].

Notwithstanding that prevention of corrosion using properly designed equipment and machineries can bring about many benefits such as saving in money, safety deems as the key reason for prevention of corrosion. More specifically, as a component of producing fluids,

H_2S can poison human and results in various type of environmental cracking [31]. The research is already ongoing on what materials can best resist H_2S. On the other hand, based on the new research findings, the industry has revised and developed new standards which can be used to determine those metals and materials which can be safely used in the environments contaminated with H_2S.

5.2 The Chemistry of Corrosion

The corrosion is essentially concerned with the oxidation of a metal, resulting in equivalent reduction reactions. Due to this process, the electrons related to the corrosion reaction are consumed. The total of corrosion reactions are often called distinctly as “half-cell” reactions. However, there is an interrelation between oxidation and reduction. When the oxidation is dominant, the electrical current of both anodes, where oxidation is dominant and cathodes where reduction predominates must be equal so that it preserves electrical charges in the whole system. Oxidation and reduction happen at the same time in the majority of metal surfaces. Should the predominant reaction be oxidation, the corrosion will set in. The most crucial reduction reaction used to decrease the chance of corrosion in oil fields is the oxygen reduction reaction. Consequently, the rate of corrosion would be considerably reduced when there is no oxygen [31].

For example a typical oxidation reaction for steel would be:

$$Fe \longrightarrow Fe^{+2} + 2e^- \qquad \text{(Eq. 2)}$$

And also the typical reduction reactions associated with corrosion are:

Hydrogen evolution

$$2H^+ + 2e^- \longrightarrow H_2 \qquad \text{(Eq. 3)}$$

Oxygen reduction in acid Solution

$$O_2 + 4eH^+ + 4e^+ \longrightarrow 2H_2O \qquad \text{(Eq. 4)}$$

Oxygen reduction in neutral or basic Solution

$$O_2 + 2H_2O + 4e^- \longrightarrow 4OH^- \qquad \text{(Eq. 5)}$$

We can also have metal ion reduction or deposition as below:

$$Fe^{+3} + e^- \longrightarrow Fe^{+2} \qquad \text{(Eq. 6)}$$

$$Fe^{+2} + 2e^- \longrightarrow Fe \qquad \text{(Eq. 7)}$$

Essentially, given the fact that there is a much lower concentration of the reducible species than higher concentration of metal in majority of environments, it follows that the reduction reaction has a function to control corrosion rate. For instance, there is less than 10 ppm of dissolved concentration of oxygen in most surface waters which are exposed to air. However, this small amount of dissolved oxygen concentration exceeds the concentration of any other reducible species. The measures to prevent the penetration of air into the water facilities are the main way whereby the internal corrosion can be controlled in equipment and channels. It is likely that multiple oxidations or reduction reactions may occur on a metal surface (e.g. in the case of alloy corrosion or when there are high levels of dissolved oxygen in an aerated acid along with the hydrogen ions of the acid). Locations such as anodes, where net oxidation reactions occur, and cathodes where net reduction reactions occur are the places where electrochemical reactions takes place. The distance between anodes and cathodes can be very short (e.g. different metallurgical phases on a metal surface). Alternatively, the distance between them can be very long (e.g. in electrochemical cells which occurs due to the different materials used in anodes and cathodes as well as differences in environment or galvanic cells) [31].

5.3 Forms of Corrosion

Dr. M. Fontana has listed different forms of corrosions in a series of papers published in Chemical and Engineering News in the 40s. They are as follows:

- Uniform attack (General corrosion)
- Galvanic or two-metal corrosion
- Pitting
- Crevice corrosion
- Intergranular corrosion
- Selective leaching
- Erosion corrosion
- Stress corrosion
- Hydrogen damage

These forms of corrosions are usually seen in applications related to oil and gas field.

The following methods are commonly used to control the above-mentioned types of corrosions:

- Material choice
- Protective coatings
- Cathodic protection
- Inhibition
- Treatment of environment
- Structural design including corrosion allowances
- Scheduled maintenance and inspection

5.3.1 Uniform attack (General corrosion)

Known as general corrosion, this form of corrosion aims to describe the situations in which the overall surface of a metal is attacked, with the metal surface slowly becoming thinner until the failure in structure occurs.

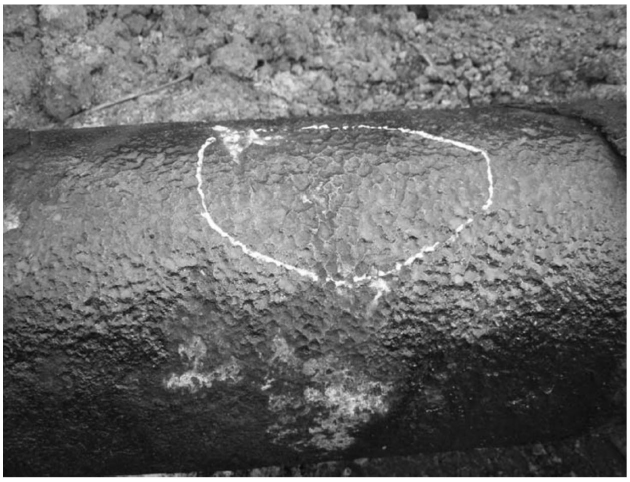


Figure 5-1 Uniform attack of pipeline exterior beneath debonded pipeline coating [31]

5.3.2 Galvanic Corrosion

Galvanic corrosion occurs when an electrochemically noble material is electrically conducted (i.e. via electrolyte) to a less noble material. In addition, this form of corrosion can happen when the circumstances lead to changes in electrochemical potential (e.g. differences in the levels of temperature and chemicals in an environment). Galvanic corrosion happens when the anode and cathode have electrical contact and they are exposed to continuous electrolytic environments such as water and wet soil.

Figure 5-2 Galvanic corrosion of galvanized piping in connection with bronze valve[31]

Table 5-1 shows the study conducted by the International Nickel Company (INC) at their seawater laboratory in North Carolina – USA. It indicated that there is a relative galvanic relationship between metals and alloys in seawater.

Table 5-1Galvanic Series of Metals and Alloys in Seawater [33]

↑	Platinum
	Gold
	Graphite
	Titanium
Nobel or Cathodic	Silver
	Chlorimet 3 (62Ni, 18Cr, 18Mo)
	Hastelloy C (62Ni, 17Cr, 15Mo)
	18-8 Mo Stainless Steel (Passive)
	18-8 stainless steel (passive)
	Chromium stainless steel 11–30% Cr (passive)
	Inconel (passive) (80Ni, 13Cr, 7Fe)
	Nickel (passive)
	Silver solder
	Monel (70Ni, 30Cu)
	Cupronickels (60-90Cu, 40-10Ni)
	Bronzes (Cu-Si)
	Copper
	Brasses (Cu-Zn)
	Chlorimet 2 (66Ni, 32Mo, 1Fe)
	Hastelloy B (60Ni, 30Mo, 6Fe, 1Mn)
	Inconel (active)
	Nickel (active)
	Tin
	Lead
	Lead - tin solders
	18-8 Mo stainless steel (active)
	18-8 stainless steel (active)
	Ni-resist (high-Ni cast iron)
	Chromium stainless steel, 13% Cr (active)
	Cast iron
	Steel or iron
Active or Anodic	2024 Aluminum (4.5Cu, 1.5Mg, 0.6Mn)
	Cadmium
	Commercially pure aluminum (1100)
↓	Zinc
	Magnesium and magnesium alloys

This table displays no voltage numbers since the fluctuations in potential vary slightly depending on the level of salinity, the extent to which there is dissolved oxygen, and other variables related to seawater. The brackets in the table indicate the metals which deem to be galvanically compatible. The alloys grouped in these brackets are somewhat similar in base composition – for example, copper and copper alloys. The bracket indicates that in most practical applications there is little danger of galvanic corrosion if metals in a given bracket are coupled or in contact with each other. This is because these materials are close together in the series and the potential generated by these couples is not great. The farther apart in the series, the greater the potential generated [33]. Note in table 5-1 the more noble position assumed by the stainless steels in the passive state as compared with the lower position of these materials when in the active condition. Similar behavior is exhibited by Inconel, which can be considered as a stainless nickel [33].

5.3.3 Pitting Corrosion

As the most common form of corrosion after uniform attack corrosion, pitting corrosion imposes heavy costs on the companies, resulting in huge money loss. One of the main challenges concerning the pitting corrosion is that it doesn’t lend itself to easy monitoring and prediction since it begins and spreads quickly within a short time. This type of corrosion is defined as follows: when overall metal surface is relatively uncorroded in some locations and they are often covered with passive films or scales, a localized attack happens on a metal surface. Figure 5-3 shows different geometries of pits in pitting corrosion.

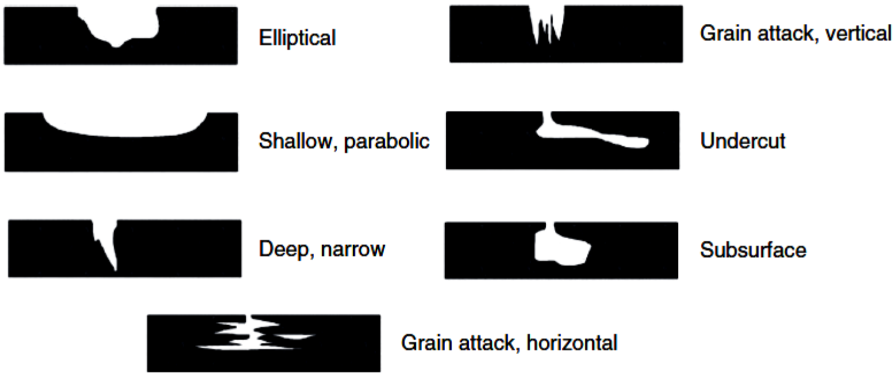


Figure 5-3 Pit morphology [31]

Film-protected alloys are more likely to form pits with relatively small surfaces and widespread corrosion beneath the pit entrance, but environmental factors, for example, scale deposits or biofilms, can also produce similar pitting patterns in carbon steel.

Pits form at defects on metal surfaces. These are often microscopic in nature and cannot be detected by field-level inspection devices. Examples of pit initiation sites include impurities or grain boundaries on the metal surface and mechanical damage to surface films, either passive films or scales

It is necessary to monitor the pitting corrosion through frequent inspection or sampling as no corrosion can happen for a long time followed by the initiation and growth of a relatively aggressive pit in and growth. Most corrosion pits are relatively shallow (Figure 5-3) yet they can work as stress concentrators, sparking Stress Corrosion Cracking (SCC) or corrosion fatigue. Defects on metal surfaces are the locations where pits are formed. As these defects cannot be seen with naked eye, the inspectors may fail to detect them. Impurities or grain boundaries on the metal surface as well as surface films damaged mechanically are some examples of pit initiation sites [33].

5.3.3.1 Pitting Resistance Equivalent Numbers (PRENs)

Higher level of resistance to pitting corrosion in different materials is represented by bigger values of PREN.

It is well known that increasing the chromium content and adding molybdenum and nitrogen as alloying elements increases stainless steels' resistance to pitting and crevice corrosion.

The most commonly used PREN is from NACE MR0176/ISO 15156. Larger values of PREN are considered to indicate greater resistance to pitting corrosion in different materials.

$$PREN = W_{Cr} + 3.3(W_{Mo} + 0.5W_W) + 16W_N \quad \text{(Eq. 8)}$$

Where: W_{Cr} is the weight percentage of chromium in the alloy, W_{Mo} is the weight percentage of molybdenum in the alloy, W_W is the weight percentage of tungsten in the alloy and W_N is the weight percentage of nitrogen in the alloy. It is important to remember that the calculated PRE only gives an indication of the resistance of stainless steels and gives no information on their behavior in real environments. Therefore, it should only be used for roughly comparing the pitting corrosion resistance of different grades.

Figure 5-4 displays the trend of deep pitting corrosion in several months. The corrosion happens on a plate made of Alloy 825 (UNS N08825). According to NACE, this alloy has an PREN in the low 30s since it is commonly taken as a very corrosion-resistant alloy. Actually, even in the case of the most corrosion-resistant alloys, pitting and Crevice corrosion may occur in high temperature brines such seawater or formation waters.

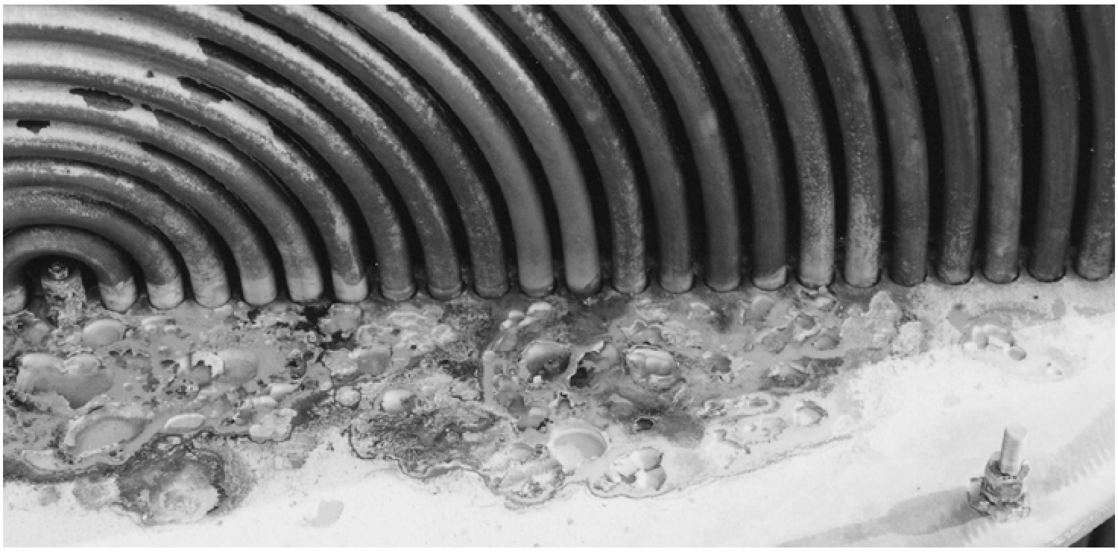


Figure 5-4 Pitting corrosion of an Alloy825 heat exchanger baffle exposed to seawater [31]

It is possible to mitigate the impact of pitting corrosion on carbon steels, using protective tools such as cathodic protection, protective coatings as well as corrosion inhibitors. In the case of martensitic stainless steels (13Cr alloys) which are used as OCTGs, the same method can be applied. The pitting and crevice corrosion resistances are different in the case of other CRAs. Adding molybdenum to the metal such as stainless steels serves as a benefit, making them more resistant. (Generally, Titanium alloys are shown to resist pitting corrosion) However, adding palladium or molybdenum can increase resistance at environments with high temperatures. [31].

5.3.3.2 Critical Pitting Temperature (CPT)

Pitting and crevice corrosion are most often caused by chlorides. Molybdenum is the alloying element that primarily provides resistance. Nitrogen enhances the effect of molybdenum. A measure of resistance to pitting corrosion is the Critical Pitting Temperature, or CPT, which is the highest temperature at which an alloy resists pitting in a given environment.

ASTM G48 Practice B is a source for test methods which cover procedures for the determination of the resistance of stainless steels and related alloys to pitting and crevice corrosion when exposed to oxidizing chloride environments. In these standard six procedures are described and identified as methods A, B, C, D, E, and F which shows the test methods for CPT and CCT (Critical Crevice Temperature) of different material groups.

5.3.4 Crevice Corrosion

The mechanisms of crevice corrosion are essentially the same as for pitting corrosion; the only important difference is that the crevice, which serves as the corrosion site, is readily visible to the unaided eye. Figure 5-5 shows locations of crevice corrosion susceptibility on a bolted connection. Problems with crevice corrosion are a major reason why bolted connections are seldom used in submerged applications, although cathodic protection to minimize crevice corrosion is possible.

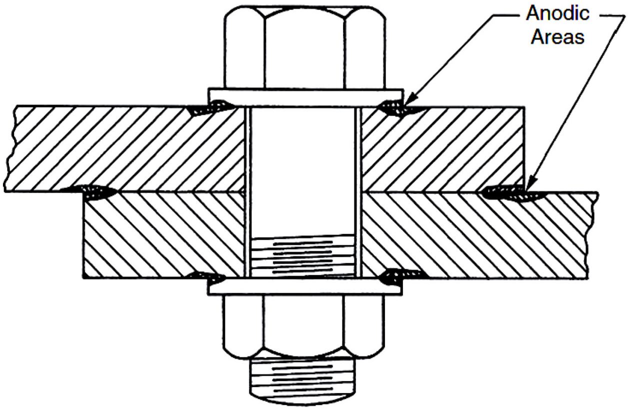


Figure 5-5 Crevice corrosion locations on a bolted connection

5.3.5 Erosion-Corrosion

Erosion corrosion is the result of a combination of an aggressive chemical environment and high fluid–surface velocities. This can emanate from a fluid flowing fast past a stationary object or it can come from the fast movement of an object within a fluid which is stationary. This can happen in the case of a ship whose propeller churns the water. Other terms have also been used by the literature (e.g. flow-enhanced or flow-accelerated corrosion). These alternative terms represent mechanisms which are not related to erosion corrosion. Erosion corrosion is mainly concerned with turbulent flow which practical piping systems need. Should lamellar (non-turbulent) flow be maintained, the fluid cannot have an adequately fast flow. Actually, this is a multiphase fluid flow that causes erosion corrosion. The flow regime maps shown below in Figure 5-6 shows how liquid (dark areas) and vapor (light areas) are distributed in vertical and horizontal flow [31]. Serious problems concerning velocity appear for slug flow, yet these patterns cannot produce erosion corrosion when there are no entrained solids. In the case of a change in flow pattern (e.g. at a rough pipe connection) which can result in a collapse and creation of shock waves and resulting effect on the protective surface ,an attack may occur due to the removal of the protective film. The flow regime maps in figure 5-6 do not show the influences of entrained solids (e.g. sand, corrosion products) which are found to speed up erosion corrosion.

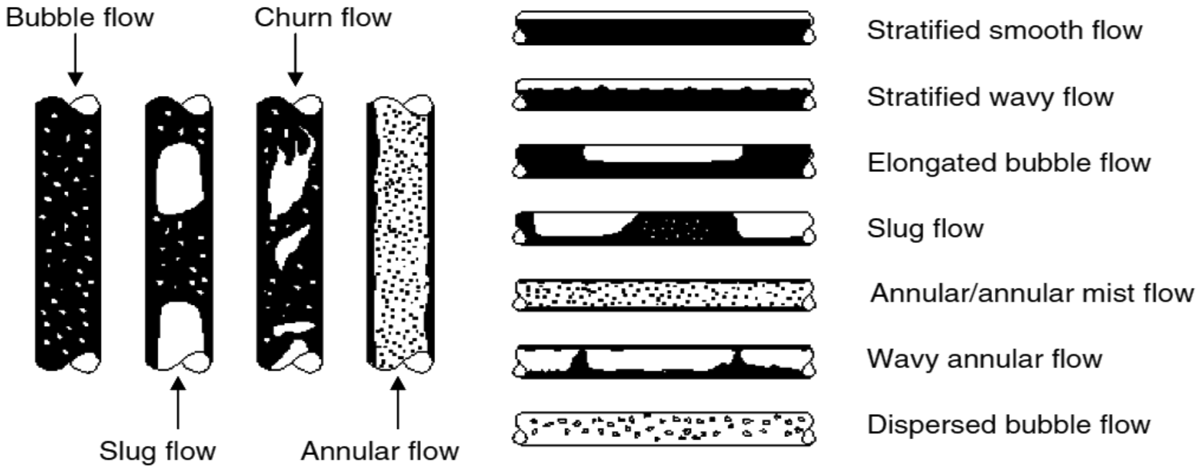


Figure 5-6 Multiphase fluid flow regimes in straight runs of vertical or horizontal piping [31]

5.3.5.1 Velocity Effects on Erosion-Corrosion

As per ANSI/API RP14E, there are different critical velocities for different metals. This number shows the highest fluid velocity that a material can tolerate prior to the occurrence of erosion corrosion. The following formula yields the critical value for topside equipment piping [34]:

$$V_{max} = \frac{C \times A}{\rho^{0.5}} \qquad \text{(Eq. 9)}$$

Where:

$V_{max} = Critical\ (maximum) velocity\ (\frac{m}{s})$

$\rho = Density\ (\frac{kg}{m^3})$

$A = Conversion\ constant\ (1.23)$

ANSI/API recommended values for the C-factor are: [34]

C = 100 *for solid-free continuous service*

C = 125 *for solids-free intermittent service*

C = 150-200 *for solids-free, noncorrosive continuous service*

C = 250 *for solids-free, noncorrosive intermittent service.*

There should be significantly reduced maximum allowable velocities for lines that contain solids. Yet, no specific guidelines have been published in this regard. Even though ANSI/API-RP14E states that the application is confined to topside service piping systems, the industry has used it for other applications such as downhole production tubing as well as for injection wells. Being set too conservatively, the maximum velocities can lead to big losses of production. In contrast, being set too high, these limits may result in erosion and possible equipment failure and hence potential loss of production. The majority of the companies believe that these guidelines and the numbers are too conservative. Consequently they work with C-factors=400 or higher and in the case of water injection (not multi-phased fluid) velocities, they use the values no more than 15m/s for CRAs (for example 13Cr).

As for materials, Duplex and austenitic stainless steels have passive films that are resistant against erosion-corrosion and can reform fast [31]. Martensitic stainless steels such as 13Cr alloys are intermediate between the Carbon steels which are not erosion-corrosion resistant (due to erosion of scale on their surfaces). They display the signs of both erosion and corrosion [31]. Recently, research finding shows that maximally 15% of failures in oil and gas production occur due to the erosion-corrosion in gravel packs, nozzles, and Christmas trees prior to finding their way in surface units and separators [31]. The use of harder and more corrosion resistant alloys can control the Erosion corrosion. Alternations in fluid velocity and changes in flow patterns can also reduce the effect of erosion corrosion.

5.3.6 Stress Corrosion Cracking (SCC)

The acronym SCC which stands for stress corrosion cracking is used for most aqueous environmental cracking that is not clearly associated with hydrogen or H_2S the common characteristic of environments that cause this form of corrosion is the presence of chlorides.

A lot of environments in which SCC occurs are mildly subject to other forms of corrosion (the basis of SCC is defined in chapter 5.3.10 – Sour corrosion). The locations where SCC initiates include pits, metallurgical defects, cracks in the surface, intergranular corrosion, and other factors that increases stress. It seems that SCC often doesn't have any corrosion products which can be visible. Stress corrosion crack grows discontinuously, it is believed to be usually associated with initiation stage and first-stage spread, secondary steady-state spread, and final fast failure. It has been suggested that these stages unfold under the influence of a mechanism called Hydrogen Embrittlement (HE). When cracking occurs in the presence of pitting or crevice corrosion i.e. active corrosion, it is called SCC. Yet, a lot of researchers believe that to be more accurate, this should be called hydrogen-assisted stress corrosion cracking (HSCC). Such a corrosion cracking usually occurs in nearly all acidic environments in which the cathodic reaction results in reduced hydrogen. An increase in the strength level of carbon steels and martensitic stainless steels usually makes the material more susceptible to this form of cracking. Generally, SCC occurs in the form of groups or colonies on otherwise un-corroded surfaces (Figure 5-8). Both external and internal cracks usually grow simultaneously and this continues until a critical flaw size is reached and final rupture happens. As Figure 5-9 shows, when small cracks come together, a circumferential crack grows around a pipeline [31].

Figure 5-7 Critical factors for SCC

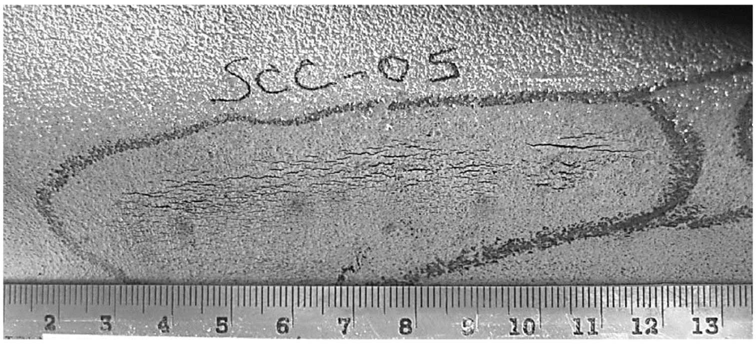


Figure 5-8 Clustered "colonies" of SCC on the outside of a carbon steel Pipeline[31]

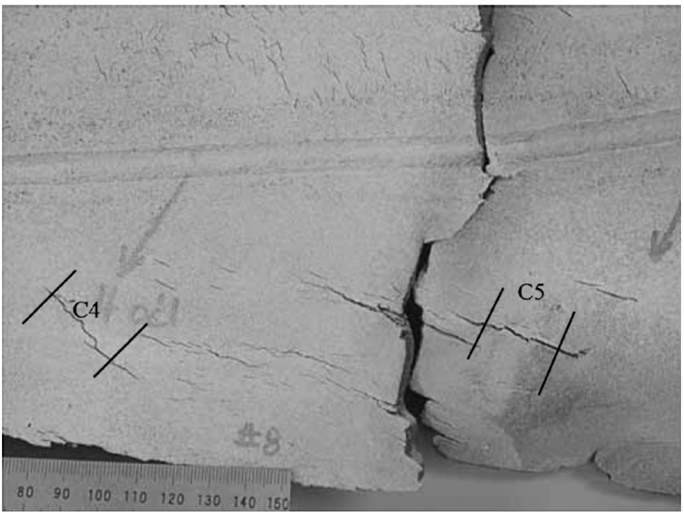


Figure 5-9 Small cracks joining together and intersecting circumferential cracks on the exterior of a pipeline[31]

SCC is controlled by avoiding metal–environment combinations that cause this problem. Other methods used to control SCC are different stress relief ways (e.g. post-weld heat treatment (PWHT), the use of protective coatings, application of corrosion inhibitors, and use of cathodic protection). The main part of such a control in the case of pipelines involves preventing the formation of stress risers as well as small defects on metal surfaces that can serve as initiation sites for SCC which would be difficult to control one it initiates [31].

In Table 5.2 A few oilfield environments are listed. It is apparent from this table that H_2S and chlorides are common to environmental cracking in most oilfield environments. Despite all of the research on environmental cracking, no screening tests have been developed that identify new environments, and all of the alloy-environment combinations have been identified due to field failures.

Table 5-2 Metals and Environmental Cracking Environments [35]

Metal	Environment	Factors that increase risk of SCC
Carbon steels	H_2S	Increasing H_2S, moderate temperatures, more acidic, higher strength/ hardness, higher stress levels
Carbon steels	Carbonates	Higher strength
Carbon steels	Chloride	Higher strength, higher stress levels, more acidic
Copper alloys	Ammonia	Higher strength, higher stress levels
Martensitic SS.	H_2S	Increasing H_2S, moderate temperatures, more acidic, higher strength/ hardness, higher stress levels

Austenitic SS.	Chlorides	Higher strength, higher chloride levels, higher stress levels, more acidic, higher temperatures, presence of H_2S
Duplex SS.	Chlorides	Higher strength, higher chloride levels, higher stress levels, more acidic, higher temperatures, presence of H_2S
Titanium	Alcohol	Higher stress levels, lower water content

5.3.7 Hydrogen-Induced Cracking (HIC)

The initiation of this form of corrosion which is described as a stepwise cracking in carbon and low-alloy steels is due to the diffusion of atomic hydrogen into the steel. This diffusion results in internal formation of hydrogen molecules at trap sites including vacancies in the metal, grain boundaries, dislocations, and second-phase particle boundaries. HIC is considered as a type of hydrogen-related cracking which requires no tensile stresses for causing cracking. What makes HIC distinct from SCC is the lack of applied stresses as HIC doesn't involve any stress. H_2S environment is always feared to be subject to HIC (as included in NACE SP0176/ISO-15156). Moreover, other environments can be conducive to the formation of such an corrosion(e.g. in strong mineral acids) .Research findings have shown that high-sulfur steels are more susceptible to HIC while new low-sulfur steels are more resistant to this type of corrosion. But, there may be conditions in low-sulfur steels that can increase the likelihood of HIC (e.g. the presence of ferrite-pearlite banding). Given the fact that in the gas vessels and containers, condensate waters don't have the mineral buffering which exists following the formation waters that accompany crude oil, there is a possibility of creation of acidic environments in gas systems. This makes these systems more corrosive compared to crude oil systems. Should gas contain H_2S, the gas systems need to be made of H_2S-resistant materials [31]. Figure 5-10 shows how HIC damages steels in sour service.

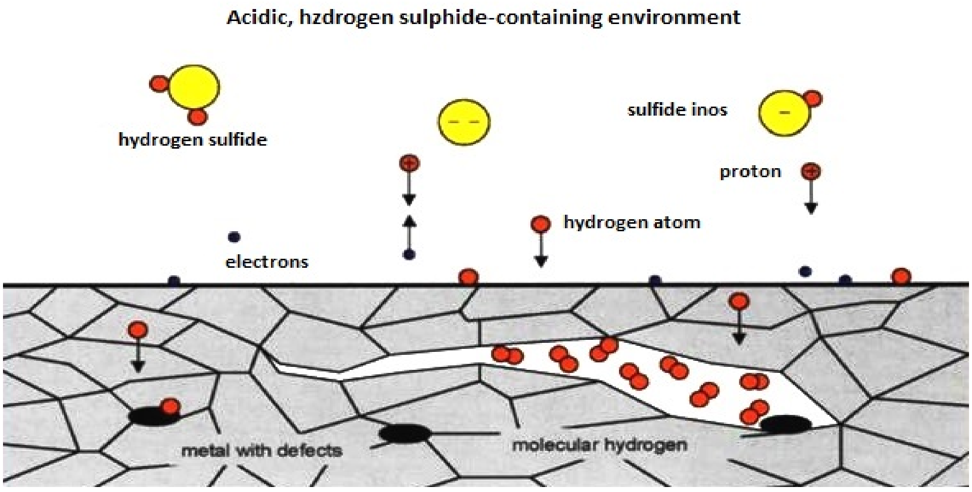


Figure 5-10 HIC in sour service [36]

5.3.8 Sulfide Stress Cracking (SSC)

The initiation of such corrosion requires a residual or applied tensile stress along with water and H_2S.

The reaction between susceptible alloys, in particular steels, and H_2S, results in the formation of metallic sulfides plus monatomic nascent hydrogen. The monatomic hydrogen which diffuses into the metal matrix serves as a product with a reduction reaction function. The diffusion of monatomic hydrogen into the metal causes internal cracking. The materials which have high level of nickel content are more resistant to SSC. This is because nickel limits surface corrosion and also causes the microstructure to have austenite which is considered as a more resistant phase compared to the ferrite commonly found in carbon and low-alloy steels. Maximum SSC susceptibility is formed in an environment with around 80°C ± 20°C (176°F ± 36°F). When the temperature is higher than this value, hydrogen gains more mobility and it is more likely to disappear from the metal prior to formation of internal defects that cause cracking [31].

5.3.9 Sweet Corrosion – CO_2 Corrosion

CO_2 corrosion which is also called sweet corrosion is considered as one of the main problems faced by oil and gas industry [37]. This form of corrosion is due to the availability of dissolved CO_2 in environments. The majority of corrosions in so far as production fluid is concerned (particularly in natural gas production) are due to CO_2. The environment in which the corrosion is caused by carbon dioxide is called *Sweet Environment*. When carbon dioxide decreases the level of water pH below 7.0, it turns into a corrosive material. pH should be measured at system conditions as CO_2 may be released due to lowering of the pressure or the rising temperature [37]. The most common way to control the sweet or CO_2 corrosion is the application of corrosion inhibitors. However, these inhibitors lose their efficacy with an increase in downhole temperatures and pressures. The following equations show the chemistry behind this type of corrosion in presence of water:

$$CO_2(g) \leftrightarrow CO_2(aq) \qquad \text{(Eq. 10)}$$

$$CO_2(aq) + H_2O \leftrightarrow H_2CO_3 \qquad \text{(Eq. 11)}$$

$$H_2CO_3 \leftrightarrow H^+ + HCO_3^- \qquad \text{(Eq. 12)}$$

$$HCO_3^-(aq) \leftrightarrow H^+(aq) + CO_3^{2-}(aq) \qquad \text{(Eq. 13)}$$

$$Fe + CO_2 + H_2O \leftrightarrow H_2 + FeCO_3 \qquad \text{(Eq. 14)}$$

(Eq.13) displays the general oxidation-reduction reaction: In the ideal conditions, $FeCO_3$ can build a protective layer, preventing more conversion of iron. When there is no water, dry carbon dioxide cannot corrode. This is because CO_2 depends on the formation of carbonic acid. (Eq.10) shows the acid-base reaction. Then, as (Eq.11) shows carbonic acid deprotonates, resulting in the production of the bicarbonate ion. With the formation of the bicarbonate ion, carbonic acid can be subject to one of two major reaction pathways. Firstly, the deprotonation of bicarbonate ions can lead to the formation of carbonate ions (Eq.12). Secondly, bicarbonate ions can undergo an anode-cathode reaction with the iron in the pipeline walls. When it comes to the corrosion reaction, two regions, namely an anodic and a cathodic one form within the pipe walls. The type of anodic or oxidation reaction is the same as in the corrosion occurring in the presence of water:

$$Fe(s) \rightarrow Fe^{2+}(aq) + 2e^{-} \quad \text{(Eq. 15)}$$

Now with the two electrons from the iron, a more complicated cathodic reaction can take place. There are two major reduction reactions that could occur, the first being with hydrogen ions and the second being with bicarbonate ions. The dominating reaction largely depends on the pH of crude oil. Under acidic conditions (pH ≅ 5), the reduction of hydrogen ions becomes the primary reaction as follows:

$$2H^{+} + 2e^{-} \rightarrow H_2(g) \quad \text{(Eq. 16)}$$

A low partial pressure of carbon dioxide in the system and a high concentration of H^+ ions because of acid dissociation may cause this. With a change in the system pH and making it more basic, the dominant cathodic reaction will be the one involving the direct reduction of the bicarbonate ion as follows:

$$2HCO_3^{-}(aq) + 2e^{-} \rightarrow H_2(g) + 2CO_3^{2-}(aq) \quad \text{(Eq. 17)}$$

The Schematic representation of an electrochemical cell for CO_2 corrosion on a steel surface.is illustrated in Figure.5-11 [38].

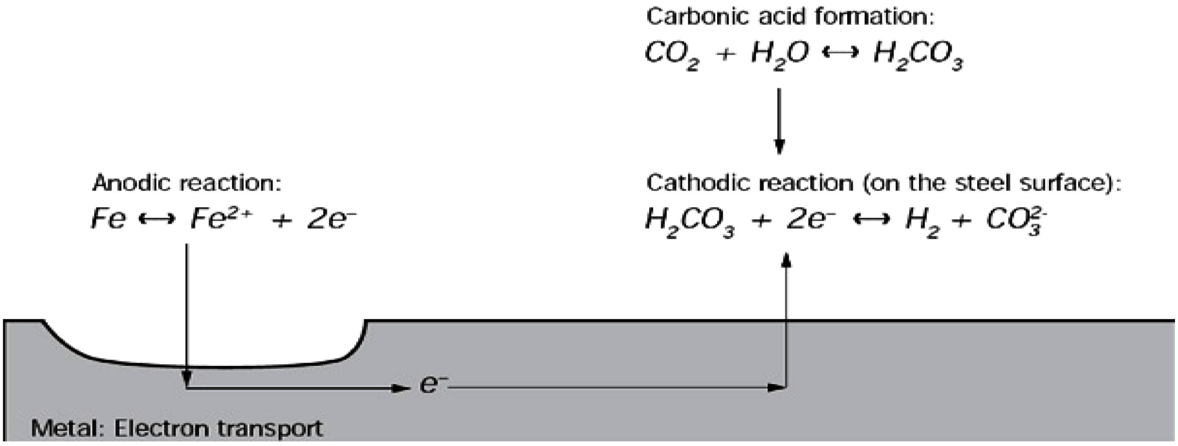


Figure 5-11 Schematic representation of an electrochemical cell for CO_2 corrosion on a steel surface [38]

5.3.10 Sour Corrosion – H_2S Corrosion

The basis of this corrosion is according to SCC (5.3.8). Sour corrosion involves a kind of corrosion that happens in production fluids because of H_2S which is considered as a weak mineral acid. Consequently, most corrosion reactions are relatively minor in these environments. Figure 5-12 makes a comparison between the impact Oxygen, CO_2, and H_2S have on corrosion. Obviously, H_2S has the least capability to corrode among these three gases [31]. The majority of problems concerning H_2S are concerned with cracking related to Hydrogen. Although it is said that the environments involving H_2S cracking have “sour” feature, the cracking is rarely described as sour corrosion.

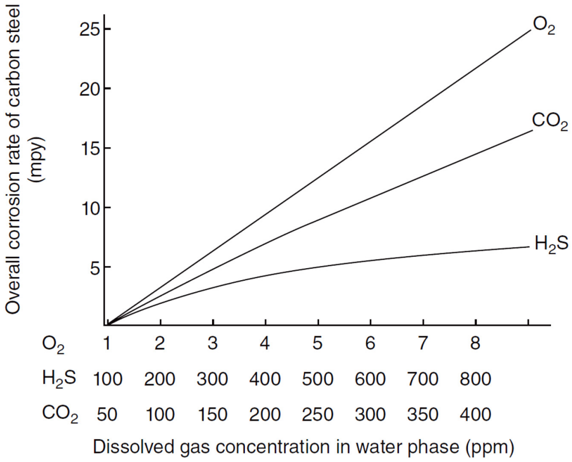


Figure 5-12 The effect of dissolved gases on the corrosion of carbon steel [31]

The corrosive power of Oxygen is almost as 50 times as that of CO_2. Compared to H_2S, Oxygen is hundred more times corrosive. The concentrations of Carbon Dioxide or H_2S in the produced fluids determine the degree of Downhole corrosion in the absence of oxygen.

Recently, oil field production environments have involved an increasing presence of H_2S and relevant corrosion considerations. Although H_2S is most likely considered as the most significant issue in modern evaluations of corrosion and cracking, the contributions of H_2S to corrosion in steels have caught the attention of more people than CO_2 corrosion. Yet, corrosion and cracking associated with H_2S are still one of the biggest issues for production operators due to the significance of H_2S related damage. [39]

H_2S plays the biggest role in corrosion of pipelines located in sour field. Hydrogen sulfide reacts with ferrous to form a H_2S film but as this film gets dissolved more and more ferrous will be available to get attacked by H_2S. This will make the pipeline thinner and thinner until its use is not safe any longer. The NACE-MR0175/ISO-15156 (Part 2. and Part 3.) concerning oil and gas production can be used for those equipment which are in contact with H_2S in order to be rated for sour service. This type of corrosion has the following chemistry:

$$H_2S\ (aq) \leftrightarrow H^+(aq) + HS^-(aq) \qquad \text{(1st dissociation reaction)} \qquad \text{(Eq. 18)}$$

$HS^-(aq) \leftrightarrow H^+(aq) + S^{2-}(aq)$ (2nd dissociation reaction) (Eq. 19)

$Fe \rightarrow Fe^{2+} + 2e^-$ (Anodic/oxidation reaction) (Eq. 20)

$Fe^{2+} + S^{2-} \rightarrow FeS \downarrow$ (Precipitation of FeS is common) (Eq. 21)

$H^+ + e^- \rightarrow H^0_{ads}$ (Cathodic/reduction reaction) (Eq. 22)

$H^0_{ads} \xrightarrow{FeS} H^0_{abs}$ (Adsorbed H-atom is absorbed) (Eq. 23)

$H^0_{ads} + H^0_{ads} \rightarrow H_2$ (Recombination reaction) (Eq. 24)

Corrosion rates for low-alloy steels in acidic H_2S-containing environments tend to increase with decreasing pH of the aqueous solutions.

5.4 Down-hole Corrosion

Downhole corrosion is the corrosion in oil and gas well equipment which are under the ground level. The downhole environment impacts such equipment. This type of corrosion mainly damages downhole equipment (e.g. screens, pumps, valves, and casings etc.). It is of enormous importance to control corrosion in production tubing as it is crucial for retaining production as well as for preventing loss of well control. The materials used in downhole need to satisfy criteria of corrosion resistance as well as mechanical requirements. It is possible to estimate the potential corrosion rate that may occur. Moreover, the risks of SSC can be assessed based on the predicted environmental conditions and flow regime. Then, based on collected corrosion data along with field experience, the types of material which are appropriate for tubing and screens can be considered. To make sure that too conservative options are not selected, the candidate materials can be subject to test considering the precise environment conditions.

5.4.1 Environmental Factors

The following basic components can pave the way for the initiation of corrosion in downhole sections [40]:

- pH
- Temperature
- Pressure
- Carbon dioxide (CO_2) partial pressure
- Hydrogen Sulfide (H_2S) partial pressure

- Dissolved Salts or Chloride content

5.4.1.1 pH

The pH level is used to measure how acidic or basic water is, serving as one of the most factors which determine if corrosion will happen. Moreover, pH impacts the type of corrosion that will occur. pH is defined as:

$$pH = -\log\ [H^+] \qquad \text{(Eq. 25)}$$

The $[H^+]$ depends on the ionization of water and varies with temperature. In standard temperature i.e. 25°C, pH of neutral water is 7.0. However, neutrality is a function of changes in temperature. That is, when temperature increases, pH decreases (e.g. in the case of pure water, pH varies from 5.5 to 5.7 at 250°C). As temperature in downhole oil and gas fields usually rises, the calculation of the in situ pH of any fluids which may affect corrosion is very important. Figure 5-13 illustrates the impact of pH on the corrosion rates of iron in water. [41]

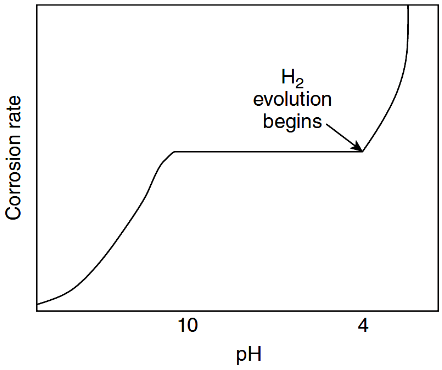


Figure 5-13 The effect of pH on the corrosion rate of iron in water at room temp. [41]

pH in oil and gas industry can range from 7.1 to 8.5 in the case of oil fields and 3.2 to 5.5 in the case of gas fields. As for acidizing job, the value can be from less than 1 to 3 [42].

5.4.1.2 Temperature Effect

Temperature makes big contribution to the initiation of the corrosion. An increase in temperature can decrease the pH level of the liquid. All over the earth, there are different geothermal gradients which influence the change in temperature. Geothermal gradient is the rate of increasing temperature with respect to increasing depth in the Earth's interior. Away from tectonic plate boundaries, it is about 25 °C per km of depth in most of the world (Figure 5-14). Yet, these gradients are not the same in different places. For example, geothermal gradient in Japan ranges from 10°C to 80°C for each kilometer of depth into the ground. In the case of Iran and based on Geo-thermometric assessment, the average temperature of deep reservoirs ranges from 130°C to 250°C [43]. Thus, selecting the suitable material that can resist the high temperature situation plays a crucial role in prevention of the corrosion and failure of equipment.

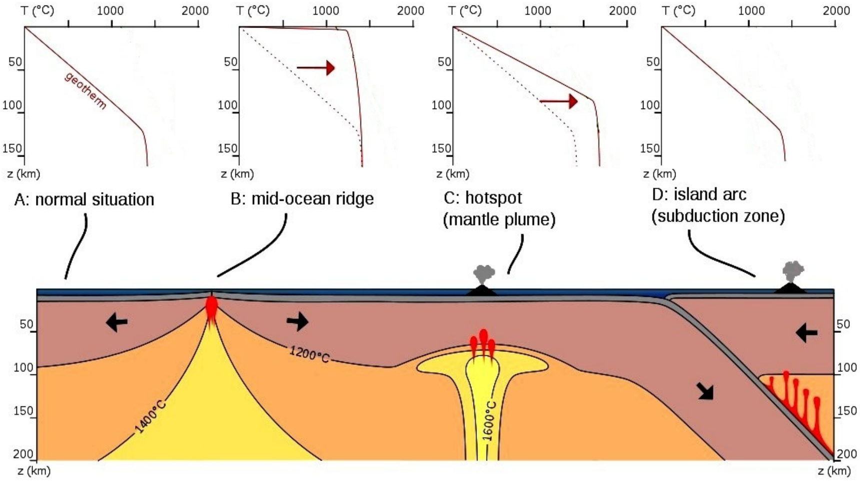


Figure 5-14 Geothermal gradient illustration [44]

5.4.1.3 Pressure Effect

In downhole situations, the following 2 sources of pressure can be calculated: 1.Fluid Hydrostatic which is related to the fluid density and its depth from the ground and 2. Effective overburden Pressure which refers to the pressure or stress imposed on the layer of soil or rock by the weight of the overlaying material. The pressure gradient of the formation needs to be taken into consideration in all downhole situations. Pressure gradient is defined as variation in pressure in each unit of depth, often indicated in units of Psi/ft or kPa/m. An increasing depth in areas where there is normal pressure results in a rise in pressure predictably. Pressure gradient is not fixed and it can change depending on types of formations as well as types of formations and salinity level. Generally, the reservoirs pressure can range from 1200Psi to 6000Psi [42]. Consequently, the materials we use for sand screens should resist this pressure in order not to face any collapse or burst failures. The definition of High Pressure High Temperature (HPHT) reservoirs is shown in Figure 5-15 [45]:

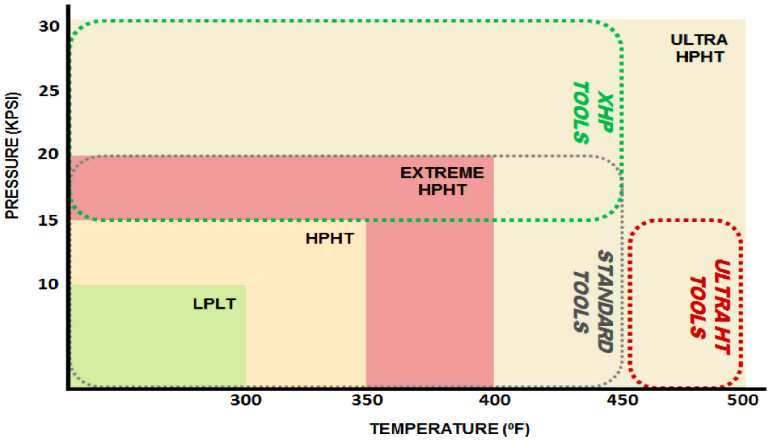


Figure 5-15 HPHT definition [45]

5.4.1.4 Salinity

Salinity is the total of all non-carbonate salts dissolved in water, usually expressed in parts per thousand (1ppt =1000 mg/L). Unlike chloride (Cl^-) concentration, you can think of salinity as a measure of the *total* salt concentration, comprised mostly of Na^+ *and* Cl^- ions. Even though there are smaller quantities of other ions in seawater (e.g., K^+, Mg^{2+}, or SO_4^{2-}), sodium and chloride ions represent about 91% of all seawater ions. Salinity is an important measurement in seawater or in estuaries where freshwater from rivers and streams mixes with salty ocean water. The salinity level in seawater is fairly constant, at about 35ppt (35,000 mg/L), while brackish estuaries may have salinity levels between 1 and 10 ppt and oil fields water around 300ppt-500ppt. Since most anions in seawater or brackish water are chloride ions, salinity can be determined from chloride concentration. The following formula is used [46].

$$\text{Salinity (ppt)} = 0.00180665\ Cl^- \text{ (mg/L)} \qquad \text{(Eq. 26)}$$

5.4.1.5 Chloride Content

Chloride content can be considered as one of the most important factors that can start corrosion in oil and gas fields. Chloride, in the form of the Cl^- ion, is considered as one of the main inorganic *anions*, or negative ions, in saltwater and freshwater. It emanates from the dissociation of salts (e.g. sodium chloride or calcium chloride) in water.

$$NaCl\ (s) \longrightarrow Na^+\ (aq) + Cl^-(aq) \qquad \text{(Eq. 27)}$$

$$CaCl_2 \longrightarrow Ca^{+2}(aq) + 2Cl^-(aq) \qquad \text{(Eq. 28)}$$

These salts as well as their chloride ions come from natural minerals, the intrusion of saltwater into estuaries as well as industrial pollution such as corrosion which leads to equipment failure. There are two types of chloride available in the crude oil:

1. Organic Chloro-Hydrocarbon
2. Inorganic chloride (such as compound of Mg and Na)

Inorganic chlorides in the raw oil that accumulate in water phase can be removed, using electrical desalting processes. The distribution of salt in crude oil is different. The most common distributions are as follows: 75%NaCl, 10%$CaCl_2$, and 15%$MgCl_2$. To put it other way, the amount of the chloride content in the raw oil is essentially controlled by the content of NaCl.

The water produced from hydrocarbon formations usually has varying amounts of chloride salts which are dissolved in solution. In this water, the concentration of the chloride can be subject to considerable variation (ranging from zero to few ppm (parts per million)).In the environments where productions are naturally deaerated, an increase in chloride ion content (from 10,000ppm to 100,000ppm) increases corrosion rate. This effect will increase if temperature increases over 60°C [39]. This combined effect originates from the incorporation and penetration of chloride ions into surface corrosion films, leading to destabilization of the corrosion film and increased corrosion. With both chloride ion concentration and temperature, the penetration of surface corrosion films increases [39].

The typical range of 10000mg/l (10ppt) up to 160000mg/l (160ppt) in oil and gas industry can be a proper estimate [42].

5.4.1.6 H_2S Partial Pressure

Corrosion rate is negatively influenced by the partial pressure of H_2S as the partial pressure of H_2S is proportional to the total pressure by:

$$P_{H_2S} = P \times Mole\ fraction\ H_2S \tag{Eq. 29}$$

It follows that an increase in pressure will increase the corrosion rate.

5.4.1.7 CO_2 Partial Pressure

Corrosion rate is negatively influenced by the partial pressure of CO_2 as the partial pressure of CO_2 is proportional to the total pressure by [47]:

$$P_{CO_2} = P \times Mole\ fraction\ CO_2 \tag{Eq. 30}$$

It follows that an increase in pressure will increase the corrosion rate.

6 Materials selection

In this chapter we will have a brief discussion about the NACE standards guidelines regarding materials selection for downhole screens and also a brief information and investigation about different material groups which were suggested and not suggested by NACE standard for sand screen design and at the end a comparison between 13 most famous alloys being used in oil and gas industry will be made in order to find the superior alloy/alloys which can be used in sweet and sour environments for sand screens.

6.1 Introduction to NACE Standard

As a famous standard, NACE has been publishing standards since 1969 and they have been accredited by National Standards Institute (ANSI) for many years. As a member of ISO, ANSI has also accredited other standards organizations based in U.S. NACE cooperates with ISO and uses its ISO standards. ISO has developed standards by drawing on NACE standards. The text of a NACE standard (by agreement) is incorporated in ISO standard. The following 3 categories of standards are published by NACE: 1. Standard Practice, 2. Standard Test Method, and 3. Standard Material Requirements. The acronym “RP” which stands for Recommended Practices were published by NACE until 2006.Due to misunderstanding of its meaning, the term “recommended” was deleted, reducing the expression to “standard practice.” These *standards* simply have different purposes which are clarified, using the extra words.

6.1.1 Test Method

These refer to the tests which involve prevention and control of corrosion. This category of standard allows the test methods of any sort to assess the features of a material, design, or operation. TM doesn’t consist of acceptance or performance criteria. SPs or MRs may cover these criteria.

6.1.2 Standard Practice:

As far as corrosion is concerned, standard practice is concerned with how a material or system is selected, designed, installed, or operated. This category of standard can give the following data: the details related to creation of a system controlling corrosion; the type of methods used to treat the materials surface with the aim of reducing requirements for applying corrosion-control devices; the criteria that are used for the appropriate operation and maintenance of a corrosion-control system; methods that are used for the appropriate application of techniques to control corrosion; procedures which are used to increase the efficacy, safety, as well as the economic benefits of an installation or system; procedures which should be used so that an installed corrosion-control system is properly used to prevent its deterioration.

6.1.3 Material Requirements

As far as corrosion is involved in the selection, application, and maintenance, material requirements are standards which are used to define required or recommended characteristics of a material. This category of standard may consist of the following details:

- Chemical composition of the material
- Mechanical properties of the material
- Physical properties of the material
- Material selection
- Other aspects of manufacture and application of the material.

6.1.3.1 NACE MR0175/MR0103

These standards have the following numbering:

- MR: Material requirement,
- 01: Version number,
- 75/03: Year 1975/2003.
- MR0175: Upstream (oil and gas production)
- MR0103: Downstream (refining and gas production)

The following section touches on the main differences between MR0175 and MR0103:

- MR0103 consist of any limitations related to environment on material
- As Ammonia's concentration in downstream is higher compared to its concentration in upstream, solubility of H_2S increases

- Welding is dominant in piping and equipment in refinery installations as MR0103 has emphasized on controlling this, in particular carbon steel.

6.1.3.2 NACE MR0175

Due to the emergence of problems related to various types of cracking, the NACE MR0175 was developed. These standards extensively underwent modifications to become NACE MR0175/ ISO15156 in 2003. Initially, the document developed in 1975 which drew on work by many NACE and other working groups was concerned only with valves and wellhead equipment. However, later revisions of these standards were expanded in later years. NACE

MR0175/ ISO15156 gave a description of various environments in which H_2S cracking was characterized as a problem, placing limitations on where carbon steel could be used in these environments in accordance with the temperature and pressure. Where the temperatures and pressures are so high that the use of carbon steel is deemed unsuitable, the use of CRAs is recommended. Some changes were made to this document over the years, motivated in part, by an increase in temperatures as well as H_2S partial pressures. Figure 3.20 and 3.21dispaly the primary version of the MR0175. They clearly indicated where MR0175 related cracking could be considered unlikely. The original versions of MR075 (1975) are limited the metals hardness up to HRC 22. This limit was derived on the basis of a set of experiments carried out by a consortium of oil companies. These experiments indicated that harder steels took shorter time to experience cracking in H_2S environments. Moreover, as figure 3.22 shows softer steels did not experience cracking under the test conditions. A lot of existing oil and gas fields were developed in accordance with the guidelines which had been developed in the early versions along with other international standards. The new studies as well as different problems with MR0175 and contradiction with other international standards resulted in a serious revision of MR0175 and the publication of shared standards called NACE MR0175/ISO15156.This set of standards was issued in 3 distinct parts and came into effect in late 2003. Milliams and Tuttle carried out a reviewing of the original NACE MR0175 and standards related to H_2S materials [48]. They also elaborated on how the new MR0175/ISO15156 documents were grouped into the following parts:

Part 1 — General principles for the selection of cracking-resistant materials

Part 2 — Cracking-resistant carbon and low-alloy steels

Part 3 — Cracking-resistant CRAs (Corrosion-resistant alloys) and other alloys

6.1.3.2.1 NACE MR0175/ISO 15156-3 (Part 3)

This section deals with how resistant the CRAs are to damages caused by:

- Sulfide Stress Cracking (SSC)
- Stress Corrosion Cracking (SCC)
- Galvanically Induced Hydrogen Cracking (GHSC)

Moreover, this part doesn’t address localized corrosion, instead focusing on cracking as the main concern. The following can be used to select CRAs and other alloys which are resistant to cracking:

- “Pre-qualified’ material Annex-A
- Following qualification by successful laboratory testing in accordance with Annex B
- Based on satisfactory two years of documented field experience.

As Annex-A shows, the identification of materials is based on materials groups. In each group, the identification of alloys is done in terms of materials type (within compositional limits) or individual alloys. Data on environmental limits are given for different materials including the H_2S partial pressure, temperature, chloride concentration, and elemental sulfur.

6.2 Material Groups

This chapter is concerned with Environmental cracking-resistant CRAs and other alloys in accordance with Annex A (already mentioned in NACE MR0175/ISO 15156-3) as well as the materials groups which can be used to list CRAs or other alloys as follows [49]:

- Austenitic Stainless Steels
- Highly Alloyed Austenitic Stainless Steels
- Solid-solution nickel-based alloys
- Ferritic stainless steel
- Martensitic Stainless Steels
- Duplex Stainless Steels
- Precipitation-hardened stainless steel
- Precipitation-hardened nickel-based alloys
- Cobalt-based Alloys
- Titanium and tantalum

Table 6-1 provides guidelines concerning the use of the materials selection tables presented in Annex A. They are based on the required equipment or component type. There are different parts devoted to different tools in this table. This thesis will focus on the part of this table where information about downhole screens with regards to the materials selection is presented.

Table 6-1 Guidance on the use of materials selection tables of Annex A based on equipment or component type [49]

Equipment or component	Material selection table numbers for various material groups									
	Austenitic stainless steel (see A.2)	Highly-alloyed austenitic stainless steel (see A.3)	Solid-solution nickel-based alloys (see A.4)	Ferritic stainless steel (see A.5)	Martensitic stainless steel (see A.6)	Duplex stainless steel (see A.7)	Precipitation-hardened stainless steel (see A.8)	Precipitation-hardened nickel-based alloys (see A.9)	Cobalt-based alloys (see A.10)	Titanium and tantalum (see A.11)
Additional materials selection tables for casing, tubing and downhole equipment										
Downhole control line tubing and downhole screens	A.7	A.11	-	-	-	-	-	-	-	-

According to table 6-1 which shows the guidance on the use of materials selection for downhole control line tubing and downhole screens, only two types of these materials are tested by NACE to be used for this purpose. This leads us to see that there is a big lack of information about other material groups which is partly going to be discussed. The concentration of this thesis will be on material groups which are listed below:

6.2.1 Austenitic Stainless Steels

As the types of materials which are most weldable, these types of stainless steels are divided into the following three groups:

- Chromium-Nickel (300 series)
- Manganese-Chromium-Nickel-Nitrogen (200 series)
- Specialty alloys.

Table 6-2 shows the maximum amount of each element according to NACE for austenitic stainless steels:

Table 6-2 Maximum amount of Austenitic stainless steels elements [49]

C (%)	**Cr** (%)	**Ni** (%)	**P** (%)	**Si** (%)	**Mn** (%)	**Si** (%)	**Mo** (%)	**N** (%)
0.08 Max	**16** Max	**8** Max	**0.045** Max	**0.04** Max	**2** Max	**2** Max	**4** Max	**0.4**

Despite the fact that generally this type is highly weldable, yet some grades may be subject to sensitization of the weld Heat-Affected Zone (HAZ) as well as weld metal hot cracking. In particular, the austenitic stainless steels are vulnerable to intergranular corrosion if *sensitized* by heating into the temperature range from 950° to 1450°F, which causes depletion of the chromium near the grain boundaries as chromium carbide is precipitated at the boundaries [50].

As Figure 6-1 indicates, austenitic stainless steels consist of Face-Centered Cubic (FCC) crystal structure (Furthermore, austenitic stainless steels are described as nonmagnetic alloys). The typical microstructure of this type for alloy 316L is illustrated in Figure 6-2.

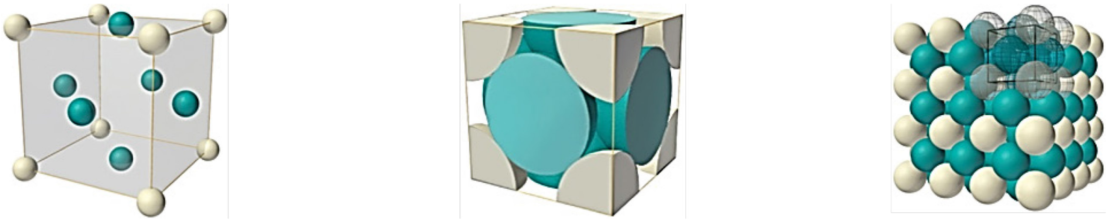


Figure 6-1 FCC crystal structure

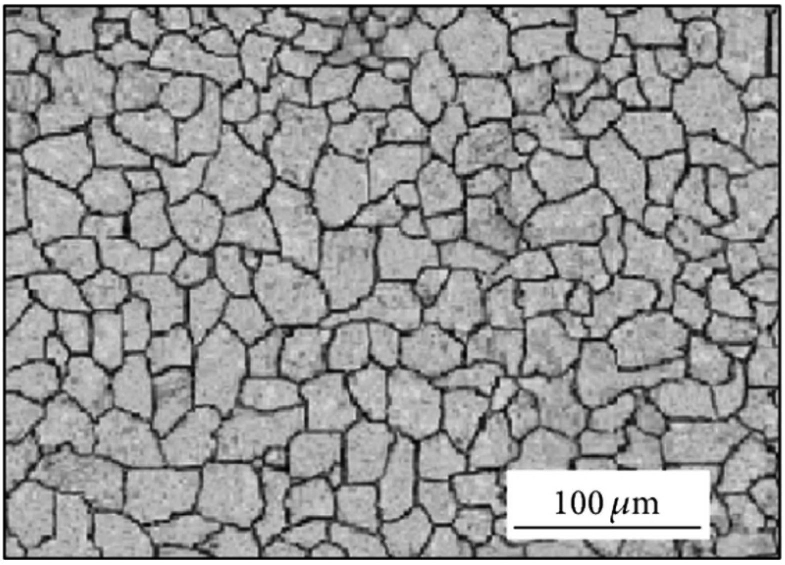


Figure 6-2 316L microstructure [51]

6.2.1.1 Environmental and materials limits for austenitic stainless steels

According to NACE MR0175 these limits are shown in Table 6-3 and Table6-4.

Table 6-3 Environmental and materials limits for austenitic stainless steels used for any equipment or components [49]

Materials type/ individual alloy UNS number	**Temperature** max °C (°F)	**Partial pressure H_2S - P_{H2S}** max kPa (psi)	**Chloride conc.** max mg/l	**pH**	**Sulfur-resistant?**	**Remarks**
Austenitic stainless steel from materials type described in MR0175	60 (140)	100 (15)	See "Remarks" column	See "Remarks" column	No	Any combination of chloride concentration and in situ pH occurring in production environments is acceptable.
	See "Remarks" column	See "Remarks" column	50	See "Remarks" column	No	These materials have been used without restrictions on temperature, PH_2S, or in situ pH in production environments. No limits on individual parameters are set, but some combinations of the values of these parameters might not be acceptable.
S31603	60 (140)	1000 (145)	50000	≥4.5	No data submitted	
	90 (194)	1000 (145)	1000	≥3.5	No data submitted	
	90 (194)	1 (0.145)	50000	≥4.5	No data submitted	
	93 (200)	10.2 (1.5)	5000	≥5	No data submitted	
	120 (248)	100 (14.5)	1000	≥3.5	No data submitted	
	149 (300)	10.2 (1.5)	1000	≥4	No data submitted	

Table 6-4 Environmental and materials limits for austenitic stainless steels used in surface applications for screen devices [49]

Materials type/ individual alloy UNS number	**Temperature** max °C (°F)	**Partial pressure H_2S - P_{H2S}** max kPa (psi)	**Chloride conc.** max mg/l	**pH**	**Sulfur-resistant?**	**Remarks**
S31600	See "Remarks" column	See "Remarks" column	See "Remarks" column	See "Remarks" column	No data submitted	This material has been used for these components without restrictions on temperature, P_{H2S}, or in situ pH in production environments. No limits on individual parameters are set, but some combinations of the values of these parameters might not be acceptable.

UNS S31600 stainless steel may be used for compression fittings and instrument tubing even though it might not satisfy the requirements stated for any equipment or component in Table 6-3.

6.2.2 Highly-alloyed Austenitic Stainless Steels

As table 6-5 shows, the amount of Cr, Ni, Mn in this type of Austenitic Stainless Steel is much higher compared to normal Austenitic Stainless Steel:

Table 6-5 Highly-alloyed Stainless Steels composition [49]

C (%)	**Cr (%)**	**Ni (%)**	**P (%)**	**Si (%)**	**Mn (%)**	**Si (%)**	**Mo (%)**	**N (%)**
0.08 Max	**25 Max**	**38 Max**	**0.045** Max	**0.04** Max	**9 Max**	**2** Max	**7** Max	**0.8**

As with other austenitic alloys, only alloying can be used to strengthen these metals and in thin section, it can be strengthened by cold working. We usually can use this type of stainless steels in situations where there is higher temperature or lower temperature than normal austenitic stainless steels. They are also more resistant to corrosion compared to other types of stainless steels (e.g. normal austenitic stainless steels, lower chromium ferritic and martensitic stainless steels). UNS N08020 (Alloy20) is considered as one of the most known types of this group. It is a nickel-iron-chromium austenitic alloy that was made for achieving maximum resistance to acid attack, specifically sulfuric acid. The typical microstructure of this type for Alloy20 is shown in Figure 6-3.

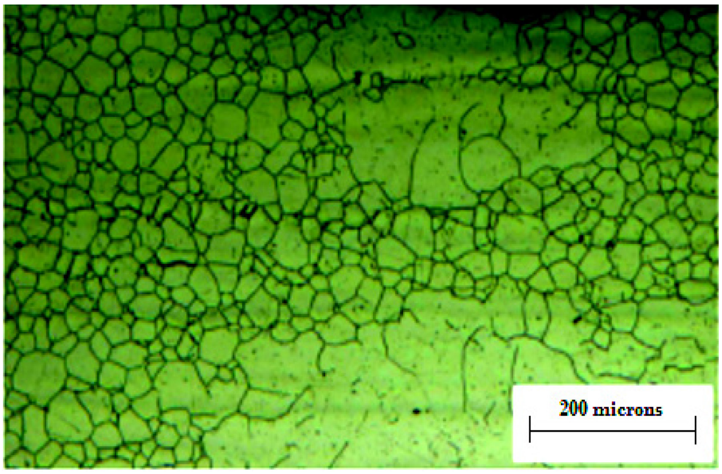


Figure 6-3 Alloy20 microstructure [52]

6.2.2.1 Environmental and materials limits for highly-alloyed austenitic stainless steels

According to NACE MR0175 these limits are shown in Table 6-6 and Table6-7.

Table 6-6 Environmental and materials limits for highly-alloyed austenitic stainless steels used for any equipment or components [49]

Materials type/ individual alloy UNS number	Temperature max °C (°F)	Partial pressure H_2S - P_{H2S} max kPa (psi)	Chloride conc. max mg/l	pH	Sulfur-resistant?	Remarks
Materials type 3a and 3b	60 (140)	100 (15)	See "Remarks" column	See "Remarks" column	No	Any combination of chloride concentration and in situ pH occurring in production environments is acceptable.
	See "Remarks" column	See "Remarks" column	50	See "Remarks" column	No	These materials have been used without restrictions on temperature, PH_2S, or in situ pH in production environments. No limits on individual parameters are set, but some combinations of the values of these parameters might not be acceptable.
Materials type 3b	121 (250)	700 (100)	5000	See "Remarks" column	No	The in situ pH values occurring in production environments are acceptable.
	149(300)	310(145)	5000	See "Remarks" column	No	
	171 (340)	100 (15)	5000	See "Remarks" column	No	

Note: These materials shall also comply with the following:

- Materials type 3a shall be highly alloyed austenitic stainless steel with (W_{Ni} + $2W_{Mo}$) >30 (where W_{Mo} has a minimum value of 2%). The symbol W represents the percentage mass fraction of the element indicated by the subscript;
- Materials type 3b shall be highly alloyed austenitic stainless steel with F_{PREN} > 40,0;
- Materials types 3a and 3b shall be in the solution-annealed condition;

Table 6-7 Environmental and materials limits for highly alloyed austenitic stainless steels used as downhole screen devices

Materials type/ individual alloy UNS number	Temperature **max °C (°F)**	Partial pressure H2S - PH2S **max kPa (psi)**	Chloride conc. **max mg/l**	pH	Sulfur-resistant?	Remarks
Materials types 3a and 3b	See "Remarks" column	See "Remarks" column	See "Remarks" column	See "Remarks" column	No data submitted	These materials have been used for these components without restrictions on temperature, P_{H2S}, or in situ pH in production environments. No limits on individual parameters are set, but some combinations of the values of these parameters might not be acceptable.

Note: These materials shall also comply with the following:

- Materials type 3a shall be highly alloyed austenitic stainless steel with (W_{Ni} + $2W_{Mo}$) >30 (where W_{Mo} has a minimum value of 2%). The symbol W represents the percentage mass fraction of the element indicated by the subscript;
- Materials type 3b shall be highly alloyed austenitic stainless steel with F_{PREN} > 40,0;

6.2.3 Ferritic Stainless Steels

These types of steel are categorized as iron-chromium alloys with Body-Centered Cubic crystal structures (Figure 6-4). Table 6-4 shows the usual composition of Ferritic Stainless Steels. The typical microstructure of this type is shown in Figure 6-5.

Figure 6-4 BCC crystal structure

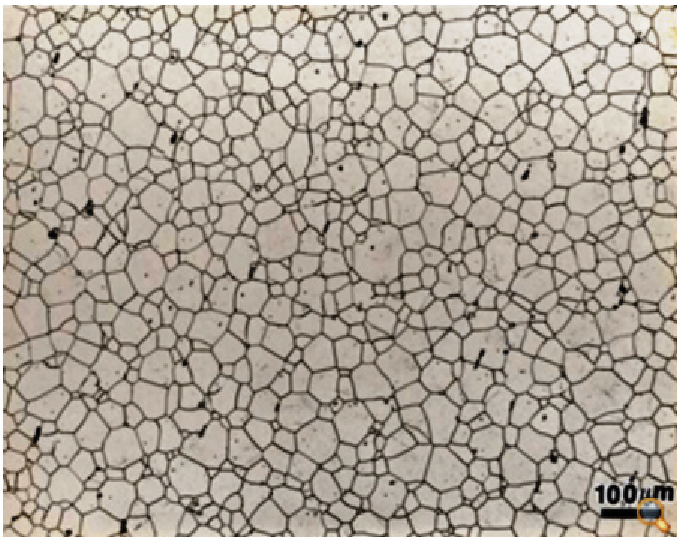


Figure 6-5 Ferritic stainless steel microstructure [54]

The following qualities of these types of steels are famous:

- Good ductility and formability,
- Poor High-temperature strengths compared to austenitic grades.
- Generally, cost less than other stainless steels.

Highly alloyed types (such as types 444 and 261) which have less C and N are highly resistant to chlorides and this makes them more expensive.

Table 6-8 Ferritic Stainless Steels composition

C (%)	Cr (%)	Ni (%)	Mo (%)	P (%)	S (%)	Mn (%)	Si (%)
0.2 Max	**30** Max	**4.5** Max	**4.5** Max	**0.04** Max	**0.45** Max	**1.5** Max	**1.5** Max

6.2.4 Martensitic Stainless Steels

Martensitic stainless steels contain more than 10.5% chromium, along with other minor elements such as carbon, nitrogen, nickel, and manganese (Table 6-5). Martensitic alloys can be hardened by heat treatment. They are similar in composition to Ferrite group with BCC structure in Hardened condition.

Table 6-9 Martensitic Stainless Steels composition

C (%)	Cr (%)	Ni (%)	Mo (%)	P (%)	S (%)	Mn (%)	Si (%)
0.22 Max	**16** Max	**7** Max	**3** Max	**0.04** Max	**0.4** Max	**1** Max	**1.5** Max

Martensitic alloys are resistant to both strength and corrosion and they are increasingly used to produce downhole tubulars and pipelines [53]. The following are the famous alloys in this group: 403, 410, 410NiMo, 420 and UNS S42000 (13Cr) and UNS S41425 (S13Cr).

6.2.5 Duplex Stainless Steels

Having a content of 22% Cr, stainless steel is normally called duplex stainless steel. However, the amounts of chromium may range from 22 to 25%. These types of steel may also have almost 5% Ni, 3% Mo, and nitrogen. The term ‘duplex’ is used for these metals as they contain 50% of ferrite and austenite phases. This type of steel has a mixture of BCC ferrite crystals and FCC austenite crystals. The term "super duplex stainless steels" may be used for those alloys which contain higher percentages of Ni and Mo. Duplex stainless steels are more resistant to corrosion compared to both ferritic and austenitic stainless steel.

Chlorides can damage Austenite and cracking may occur in ferrites which are located in H_2S environments. Given that both phases are combined in one alloy, the initiation of cracking in one phase is often slowed and stopped when they reach the other phase. However, the use of this type of alloy is occasionally confined to a temperature limit of 65°C (150°F) in the presence of chlorides.

UNS S31803 (2205 or 22Cr) and UNS S32750 (2507 or 25Cr) are the most known alloys of this group. They are being used in oil and gas industry. As a requirement of NACE RP0175/ISO15156, duplex stainless steels which are used in H_2S service should be solution annealed. i.e. it should meet thermodynamic equilibrium [49]. The typical microstructure of this type for alloy 22% Cr is shown in Figure 6-6.

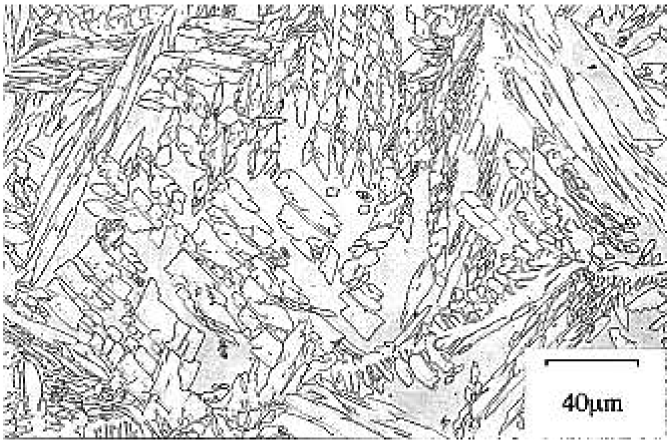


Figure 6-6 22%Cr microstructure [56]

6.2.6 Nickel-based Alloys

The following are two types of nickel-based alloys:

- Solid-solution alloys
- Precipitation-hardened alloys

The structure of pure nickel and the solid-solution alloys is FCC which is similar to austenitic stainless steels. These types of alloys are ductile but have limited strength.

The upstream oil field operations experience fewer restrictions as they are carried out in an environment which is confined to temperatures of 450°F (230°C) and less. In contrast, in the case of processing and refining, high-temperature processing is normal and consequently having strength in the face of high temperature is important.

Compared to the iron-based alloys already discussed, the price of these alloys is higher and their application is confined to very corrosive environments in which other types of alloys cannot be used. UNS N06625 (also known as 625), UNS N08028 (also known as Alloy28), UNS N08825 (also known as 825), and UNS N10276 (also known as C276) are some examples of this type.

6.3 Sand Screens Material Selections

This chapter discusses some well-known CRAs and their potential application as downhole screens. These CRAs are made up of various materials groups already described and they are considered as the most famous alloy in each group. As already discussed, only Austenitic Stainless Steels and Highly-alloyed Austenitic Stainless Steels (Table 6-1) are the materials which according to NACE MR0175/ISO 15156-3 – Annex A can be used for downhole screens (NACE has done special investigation about austenitic and highly austenitic stainless steels although they are not precise enough). This chapter aims to make a comparison between all groups of materials so as to identify the superior alloy or alloys which have the following features: they can withstand the sour and sweet borehole environments. Moreover, weaker alloys which are being used by oil and gas industry can replace them later. To this end, groups of materials will be compared with each other in terms of their corrosion resistance (PREN, CPT), Mechanical Properties (such as Hardness, Tensile Strength (Yield) and Tensile Strength (Ultimate)). Finally, the conclusion can be reached.

The Alloys which are going to be compared are as follows:

• 316L	(Austenitic Stainless Steel)
• Alloy20	(Highly-alloyed Austenitic Stainless)
• 825	(Nickel-based Alloys)
• Alloy28	(Nickel-based Alloys)
• 2550	(Nickel-based Alloys)
• 625	(Nickel-based Alloys)
• C276	(Nickel-based Alloys)
• 13Cr	(Martensitic Stainless Steel)
• S13Cr	(Martensitic Stainless Steel)
• 2205	(Duplex Stainless Steel)
• 2507	(Duplex Stainless Steel)
• P560 Extra	(BÖHLER)
• A975 Extra	(BÖHLER)

6.3.1 316L (Austenitic Stainless Steel)

As a low carbon version of 316 Grade, 316L is more resistant to corrosion than 316. Due to its cost effective corrosion resistance and easy fabrication, this type of steel is widely used by the oil and gas and chemical industries. 316 and 316L stainless steel are not different in terms of their price.

As already discussed in Chapter-4, all types of sand screens use this type of alloy although its PREN is very low compared to other alloys which can be substituted with in sweet and sour environments. Figure 6-7 illustrates when there is NaCl and CO_2, the use of 316 is limited only by certain temperature. For instance, if there are 200g/l (200000ppm) of NaCl and 2500psi of CO_2 in an environment, then the temperature should not exceed 60°C otherwise corrosion happens. The conditions involving the presence of H_2S are very sensitive to chloride ions. The environments where is no or little chloride (<50ppm) are reliable and they should be included in sour gas handling facilities. Pitting corrosion can occur in the absence of O_2. So it should be used only in deaerated, non-H_2S containing conditions.

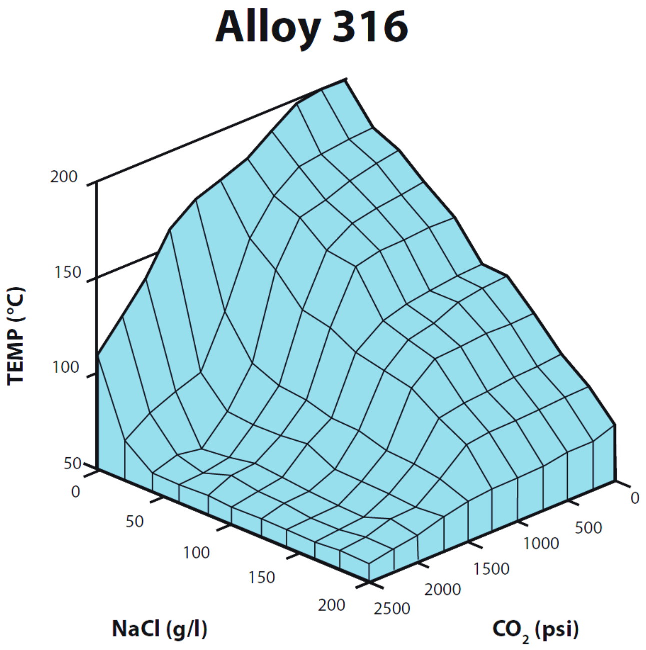


Figure 6-7 The corrosion resistance of Alloy 316/316L in CO_2/NaCl environments in the absence of oxygen and H_2S. Corrosion rates of ≤0.05 mm/yr. (2mpy) and no SSC or SCC [55]

6.3.2 13Cr & S13Cr (Martensitic Stainless Steel)

Figure 6-8 shows those regions in which 13Cr (UNS S42000) stainless steel containing NaCl can be exposed to carbon dioxide. This figure only applies when there are no O_2 and H_2S. When there is chloride, even the small amount of oxygen can lead to large pitting of 13Cr. That's why proper storage of 13Cr plays a crucial role in its long-term corrosion resistance. Generally, given that there is not much oxygen in the environments where downhole primary producing is underway, 13Cr doesn't come in contact with sufficient O_2 and there will be no problem. However, for surface equipment it must be considered and the diagram in Figure 6-4 will not be applicable.

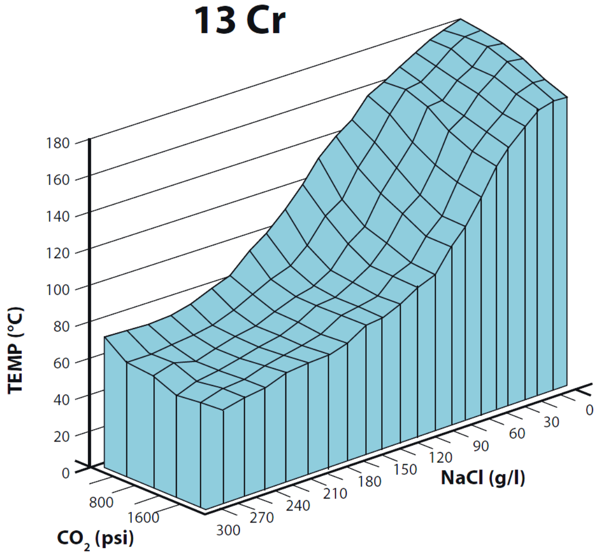


Figure 6-8 The corrosion resistance of Alloy 13Cr in CO_2/NaCl environments in the absence of oxygen and H_2S. Corrosion rates of ≤0.05 mm/yr. (2mpy) and no SSC or SCC [55]

S13Cr (UNS S41425) which have different names such as Super 16Cr, Hyper 13Cr or modified 13Cr are commonly stronger compared to the basic API 13Cr grade. They can be useful in environments with 30°C higher operating temperature when there is no H_2S. Many workers have studied the effect of H_2S on its performance under sour conditions. According to the latest data from laboratory work and field studies, standard API 13Cr L80 can be resistant to a little higher H_2S compared to what earlier findings suggested [57]. Figure 6-9 indicates a set of conditions in which the material is resistant to SSC as well as the region at low pH or higher H_2S where cracking will occur in the material in standard SSC test conditions.

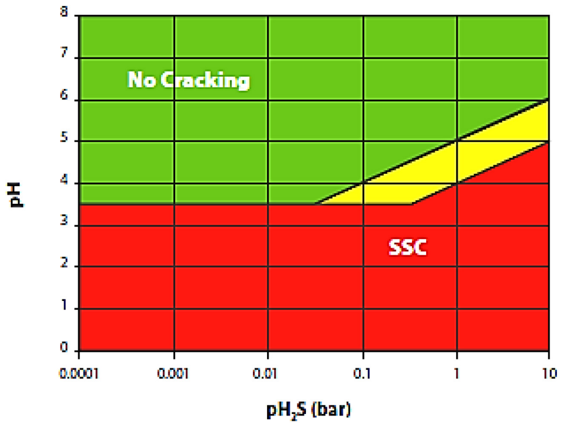


Figure 6-9 Limits for 13Cr in Sour Service [55]

The conditions where API L80 13Cr material may be susceptible to SSC are shown in red while the condition where the same material is resistant to SSC is shown in green. The yellow area shows the conditions which need to be studied more for alloy behavior.

The findings show that S13Cr grade is more susceptible to H_2S compared to the standard 13Cr grade. Perhaps this is an indicator of its higher strength. According to a study, the effect of material yield strength on performance shows that the presence of ‘cold work’ in the material poses a risk concerning accelerated initiation of pitting, HE and SSC [57] (Figure 6-10).

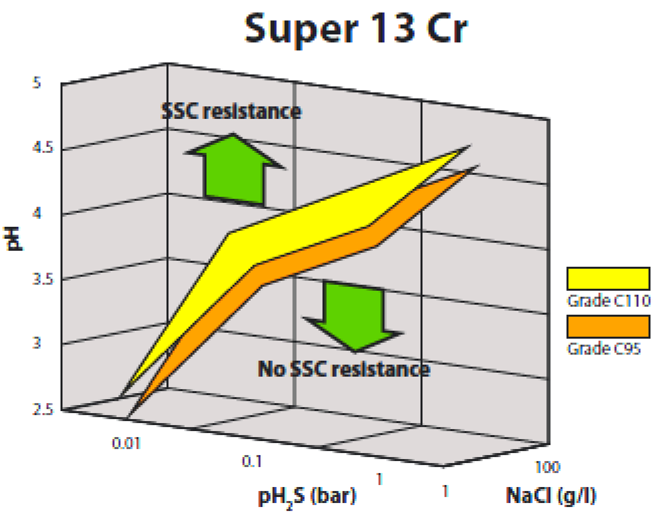


Figure 6-10 SSC susceptibility diagram of a S13Cr.[57]

6.3.3 22Cr & 25Cr (Duplex Stainless Steel)

A comparison between Figure 6-7, Figure 6-8 and Figure 6-11 shows that the resistance of 22Cr (UNS S31803) duplex stainless steel is significantly higher than 13Cr and 316L in the environments where there is no H_2S even in the face of higher temperatures.

The 25Cr (UNS S32750) stainless steels are more resistant to pitting compared to the 22Cr duplex steels. This feature enhances the usability range by about 30°C for any condition compared to the 22Cr grade. In the presence of H_2S, the performance of duplex stainless steels becomes sensitive to chloride ions. To increase its strength, the duplex stainless steels are cold worked in some applications. It is claimed that this doesn’t affect their resistance to corrosion in CO_2/NaCl but can have a large harmful impact on their resistance in H_2S service.

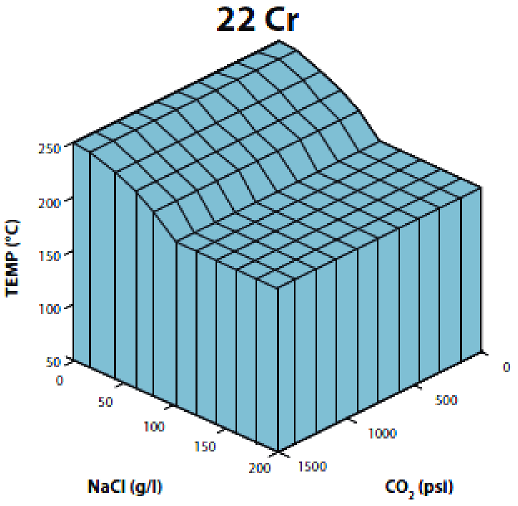


Figure 6-11 The corrosion resistance of 22Cr duplex in CO_2/NaCl environments in the absence of oxygen and H_2S, Corrosion rates of ≤0.05 mm/yr. (2mpy) and no SSC or SCC [55]

6.3.4 Alloy20 (Solid Solution Nickel-based Alloys and Highly-alloyed Austenitic stainless steel)

Known as Carpenter 20, aloy20 (UNS N08020) is a type of a nickel-iron-chromium alloy which was developed to maximally increase resistance to acid attack, in particular sulfuric acid. This alloy is highly resistant to various types of corrosion including pitting as well as crevice corrosion in chemicals those contain chlorides, sulfuric, phosphoric, and nitric acids. It also consists of niobium in order to stabilize the alloy against sensitization and resulting intergranular corrosion. There is a controversy over whether Carpenter20 can be considered as a stainless steel or a nickel alloy. This is because the nickel content is just on the border of defining it as one way or the other. Thus, this alloy may be described as Alloy20 Stainless Steel or as a nickel alloy depending on the individual you are talking to. The behavior of this alloy is similar to that of 316L but maybe a bit better when it comes to resistance against the corrosion as the PREN for Alloy20 is more (not much) than 316L.

6.3.5 Alloy28 (Solid Solution Nickel-based Alloys)

The addition of molybdenum and copper to nickel-iron-chromium alloy yields alloy 28 (UNS N08028) which is highly resistant to both reducing and oxidizing acids, SCC, as well as to localized attack (e.g. as pitting and crevice corrosion).

The gas and oil industry has successfully used Alloy 28 for downhole tubing and casing liners [55]. Figure 6-12 indicates the set of applicability for Alloy28 which resists better against environments containing H_2S compared to other stainless steels. Alloy 28 is slightly resistant to SCC from elemental Sulphur. Thus, applications that contain Sulphur combined with chlorides and H_2S should be assessed further in those environments.

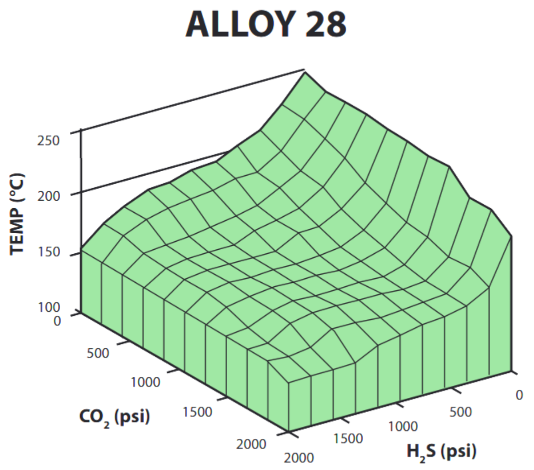


Figure 6-12 The corrosion resistance of Alloy28 in H_2S/CO_2 environments in the absence of elemental sulphur, Corrosion rates of ≤0.05 mm/yr (2mpy) and no SSC or SCC [55]

6.3.6 Alloy625 (Solid Solution Nickel-based Alloys)

As a Ni-Cr-Mo alloy, Alloy625 (UNS N06625) is used because of its high strength, good toughness, its oxidation as well as corrosion resistance. Although the alloy was mainly intended to be used for high temperature strength, its highly alloyed structure makes the metal highly resistant against general corrosion. Given its high alloy content, alloy625 can resist against diverse severe corrosive environments. Consequently, no attack occurs in mild environments (e.g. fresh and sea water, neutral pH environment, and alkaline media). Due to its high molybdenum content, the alloy is very resistant to pitting and crevice corrosion.

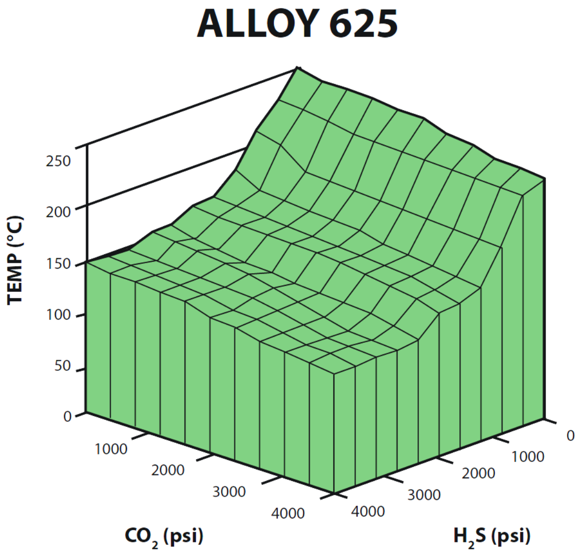


Figure 6-13 The corrosion resistance of Alloy625 in H_2S/CO_2 environments in the absence of elemental sulphur, Corrosion rates of ≤0.05 mm/yr (2mpy) and no SSC or SCC [55]

6.3.7 Alloy825 (Solid Solution Nickel-based Alloys)

Alloy825 can resist against all CO_2 concentration and it is only sensitive to H_2S, temperature and high concentration of chloride. Figure 6-14 shows this nickel-based alloy.

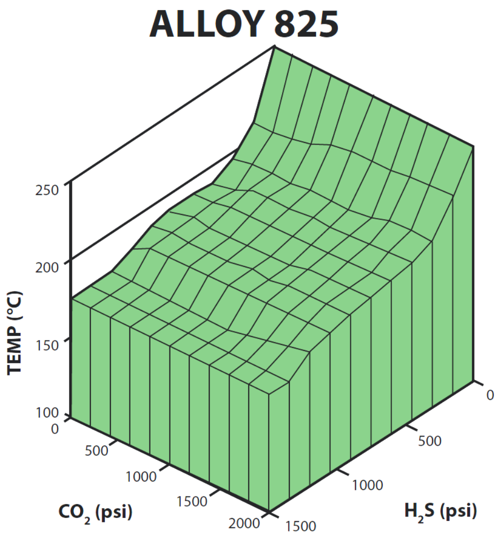


Figure 6-14 The corrosion resistance of Alloy825 in H_2S/CO_2 environments in the absence of elemental sulphur, Corrosion rates of ≤0.05 mm/yr (2mpy) and no SSC or SCC [55]

6.3.8 Alloy2550 (Solid Solution Nickel-based Alloys)

Alloy2550 (UNS N06975) can resist against all CO_2 concentration and it is only sensitive to H_2S, temperature and high concentration of chloride. Figure 6-15 shows this nickel-based alloy.

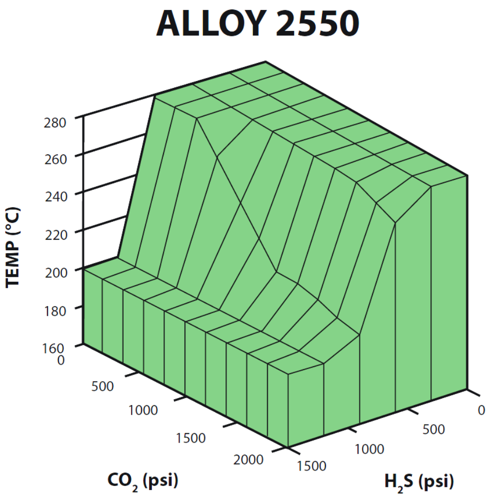


Figure 6-15 The corrosion resistance of Alloy2550 in H_2S/CO_2 environments in the absence of elemental sulphur, Corrosion rates of ≤0.05 mm/yr (2mpy) and no SSC or SCC [55]

6.3.9 Alloy C-276 (Solid Solution Nickel-based Alloys)

Alloy C-276 (UNS N10276) is highly resistant against corrosion in a various aggressive media. The high molybdenum content transfers resistance to localized corrosion (e.g. pitting). C-276 resists against general corrosion, SCC, pitting and crevice corrosion in a wide range of severe environments.

As Figure 6-16 shows, C-276 can resist against all CO_2 concentration and H_2S concentration in the temperature up to the 260°C. During welding, the low level of carbon reduces carbide precipitation, resulting in maintenance of the resistance against intergranular attack in HAZ of welded joints.

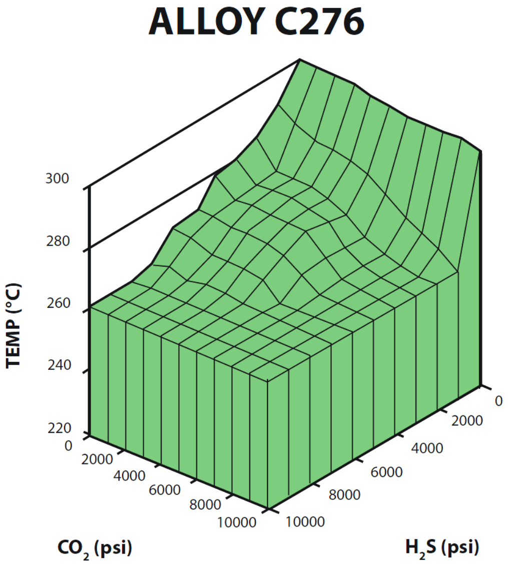


Figure 6-16 The corrosion resistance of Alloy C-276 in H_2S/CO_2 environments in the absence of elemental sulphur, Corrosion rates of ≤0.05 mm/yr (2mpy) and no SSC or SCC [55]

6.3.10 Alloy A975 Extra & P560 Extra (BÖHLER Edelstahl)

Böhler Edelstahl Company (Kapfenberg-Austria) has introduced these alloys for further evaluations regarding whether they can be used as sand screens in environments containing H_2S and CO_2. Table 6-6 shows the chemical compositions of these alloys:

Table 6-10 Chemical composition of Böhler Edelstahl Company alloys

Alloy	**Nominal chemical composition of alloy (Wt. %)**							
	C	**Si**	**Mn**	**Cr**	**Mo**	**Ni**	**Nb**	**Other**
P560 Extra	0.06 Max	0.20	23.4	21.30	0.20	1.50	-	N=0.90
A975 Extra	0.02	0.30	2.8	27.4	3.3	29.4	-	N=0.28

.

A975 Extra has a **PREN = 42.77** and *P560 Extra* has a **PREN = 36.36** making them both better corrosion resistant alloy compared to 13Cr, S13Cr, 316L, Alloy825, 22Cr, Alloy20,

6.4 Sand Screens Material Selections Results

We already have introduced 13 different alloys in chapter 6. This section represents the results of comparisons between these 13 alloys in Table 6-11.

Table 6-11 Comparison of different alloys

Increasing PREN

Alloy	UNS Number	Nominal chemical composition of alloy (Wt. %)										Corrosion Resistance		Mechanical Properties			
		C	Cr	Ni	Mn	Si	P	S	Mo	N	Other	PREN	CPT (°C) (FeCl3) ASTM G48	HRC	Typical Properties, MPa		Typical Min Design Temp
															Min YS	Min TS	(°C)
13Cr	S42000	0.2	13	0	1	1	0.04	0.03	0	0	-	13	NA	22			
S13Cr	S41425	0.1	14	5.5	0.75	0.5	0.02	0.01	1.75	0.1	Cu 0.3	20.715	NA	28	500	600	
316L	S31603	0	17	12	2	1	0.05	0.03	2.5	0	-	25.25	24 **	22	205	515	-196
Alloy 20	N08020	0.1	20	35	2	1	0.05	0.04	2.5	0	Cu 3.5	28.25	NA	35			
Alloy 825	N08825	0.1	22	42	1	0.5	0	0.03	3	0	Ti 0.9, Cu 2	31.4	25	35-40	175	515	-196
22Cr duplex	S31803	0	22	5.5	2	1	0.03	0.02	3	0.1	-	34.14	42 **	25	450	620	-50
P560 Extra	BÖHLER	0.1	21	1.5	23.4	0.2	-	-	0.2	0.9	-	36.36	NA	29-53			
Alloy 28	N08028	0	27	31	2.5	1	0.03	0.03	3.5	0	Cu 1.0	38.55	54 **	33	215	550	-196
25Cr duplex	S32750	0	25	7	1.2	0.8	0.04	0.02	4	0.3	-	42.68	85	36	550	800	-46
A975 Extra	BÖHLER	0	27	29	2.8	0.3	-	-	3.3	0.3	-	42.77	75	93.5 HRB			
2550	N06975	0	25	50	1	1	0.03	0.03	6	0	Ti 1.1	44.3	NA	35-40			
Alloy 625	N06625	0.1	22	Bal.	0.5	0.5	0.02	0.02	9	0	Nb 3.65	51.2	96 *	35-40	415	825	-196
C-276	N10276	0	16	Bal.	1	0.1	0	0.03	16	0	W 3.75	74.488	102 *	45	280	690	-196

The data in this chart are extracted from [58] (Shown in Yellow), [31] (shown with **), [59] (Shown with *) and [49]. Those which are shown in red are missing data which need further investigations. The PREN (F_{PREN}) shall be calculated as: $F_{PREN} = W_{Cr} + 3.3 (W_{Mo} + 0.5 W_{W}) + 16 W_{N}$.

7 Sand Screens Market Share

In this chapter a detailed overview and the forecast of the sand control systems markets by type, applications in onshore and offshore, and global region which was studied in 2014 will be presented. [60].

7.1 Sand Control Systems Market (2014 VS 2019)

The global Sand Control Systems market is expected to be valued at $2,367 million in 2014, and is believed to reach $4,035 million by 2019, with the Compound Annual Growth Rate (CAGR) of 11.3% from 2014 to 2019. The reason for this growth is largely dependent on growing exploration activities across the globe and also the recent discoveries of oil and gas reserves in remote areas (such as natural gas discovery in fields of Tanzania and Mozambique in West Africa) along with increasing technological advancements in terms of equipment which have made drilling operations more feasible and cost-effective. Figure 7-1 is representative of sand control systems market snapshot (2014 vs 2019). Gravel pack systems are estimated to account for the largest market size of $909 million in 2014, while inflow control devices are projected to grow at the highest CAGR of 12.1% from 2014 to 2019. Growing onshore and offshore activities with new discoveries and field developments in the offshore regions of the Gulf of Mexico (GOM), West Africa, the Middle East, and Asia-Pacific are the key factors behind the growth of inflow control devices.

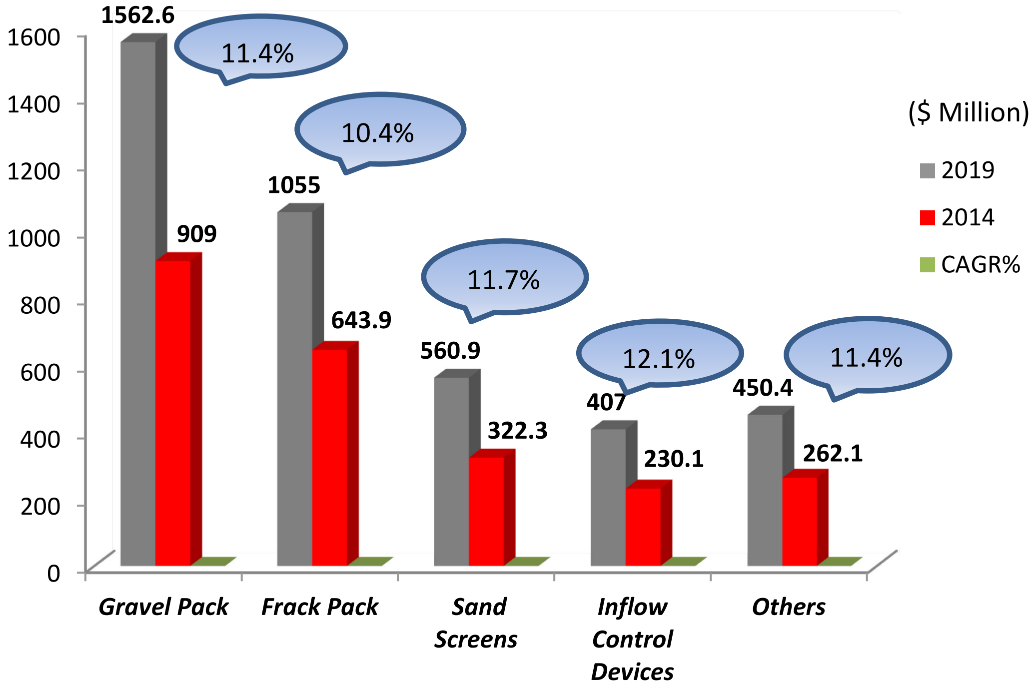


Figure 7-1 Sand control systems market (2014 VS 2019) [60]

Note for the chart: Others include cased and open-hole completions and combination of gravel pack and sand screens systems.

On the basis of application, the global Sand Control Systems market has been divided into onshore and offshore. As it is shown in Figure 7-2 the onshore application accounted for the largest share of 83% of the Sand Control Systems market in 2014, whereas offshore application is poised to grow at a high CAGR of 15.1% from 2014 to 2019. Growing demand for deep-water activities in Asia-Pacific and further drilling into mid ocean are driving the demand for Sand Control Systems in offshore fields.

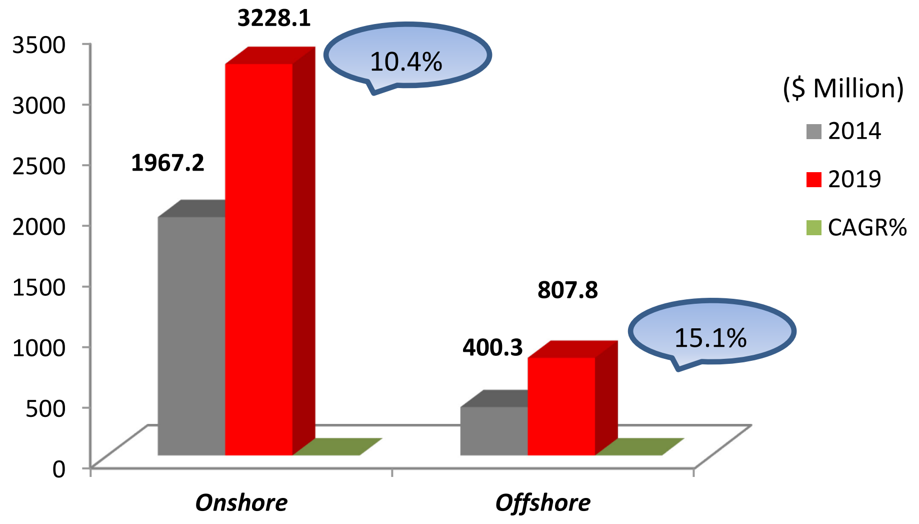


Figure 7-2 Sand control systems market, by application [60]

On the basis of the region, North America accounted for the largest share of 45% of the global Sand Control Systems market in 2014. The region has abundant onshore potential reserves of oil & gas. Furthermore, factors such as presence of leading oil & gas field operators and service providers with increasing investments in E&P CAPEX in the region are resulting in more onshore and offshore exploration and production activities, thereby increasing the demand for Sand Control Systems. However, the recent decline in oil prices could limit offshore spending in the region; it is thus a major restraint of Sand Control Systems being used in new drilled wells.

South America and Asia-Pacific are expected to grow at CAGRs of 16.8% and 11.0% from 2014 to 2019, respectively. The growth of the Sand Control Systems market in these regions is propelled by factors such as growing offshore activities in Brazil, China, and Australia. The growth rate of the European region is determined by growing offshore activities in the North Sea. Additionally, companies opting for ultra-deep-water explorations in the region are driving the demand for efficient production in the offshore region. Dependence on crude oil & gas for use in industries and other applications also fuels the growth of South America and Asia-Pacific regions.

The Sand Control Systems market is a consolidated and competitive market with a small numbers of players. The key players of this market include Schlumberger Limited (U.S.), Halliburton (U.S.), National Oilwell Varco (U.S.), Weatherford International (Switzerland), and Cameron International(U.S.). These companies provide tools as well as consulting services to operators of oil & gas fields.

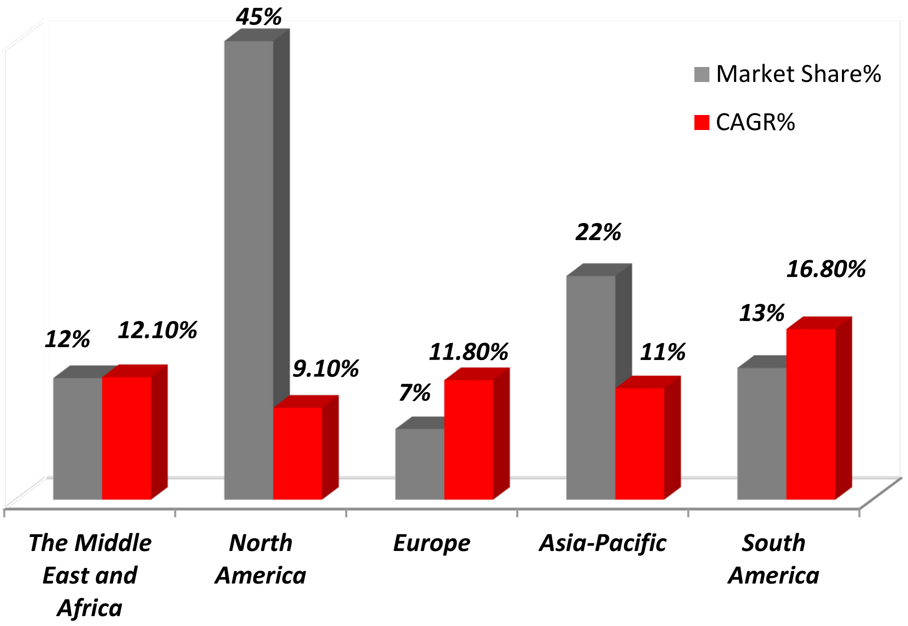


Figure 7-3 Sand control systems global market share in 2014 and expected CAGR% [60]

Note: CAGR is calculated for the period of 2014 to 2019.

The North America region is expected to grow at a CAGR of 9.1% from 2014 to 2019. Discoveries in the U.S. Gulf of Mexico and a shift from conventional to unconventional wells drive the Sand Control Systems market in this region. The U.S. is shifting its focus from conventional to unconventional wells, which would lead to increased utilization of Sand Control Systems. The country is expected to have the highest share and dominate the market in 2014 due to high number of onshore wells, globally. High demand for oil production in the U.S., Canada, and Mexico leads the market for well completion services in these countries. Asia-Pacific is the second-largest market for Sand Control Systems with an estimated market share of 22.2%, globally. Europe is estimated to capture a market share of 7.4% in 2014 due to demand for oil production from the North Sea region. In the Middle East and African region, such as UAE, Saudi Arabia, Iran, Nigeria and Angola have a huge scope of oil production. Iran after sanctions is one of the major oil producing countries along with Nigeria, Angola and UAE in the region. Various operators are able to invest heavily in the well completion services as the governments are spending more in E&P activities.

The decreasing trend of crude oil prices could affect the Sand Control Systems market as well. Low crude prices could affect global E&P and other oilfield services spending due to lack of funds and reduced profit margins. Consequently, various companies could bypass well completion operations, such as Sand Control Systems, in order to increase their profit margins and reduce additional costs. Moreover, the sudden fall of oil prices could also lead to a halt of various oilfield operations, which would eventually affect the market for Sand Control Systems.

7.2 Sand Control Systems Market Size, by Type (2014 to 2019)

Sand Control Systems comprises various types that include gravel packs, frac-packs, sand screens, and inflow control devices, among others. The global Sand Control Systems market in 2014 is led by gravel pack systems with a market share of 38.4% followed by frac-pack with 27.2% and sand screens with 13.6%, globally. Figure 7-4 is a representative of sand control systems market size, by type, from 2012 to 2019.

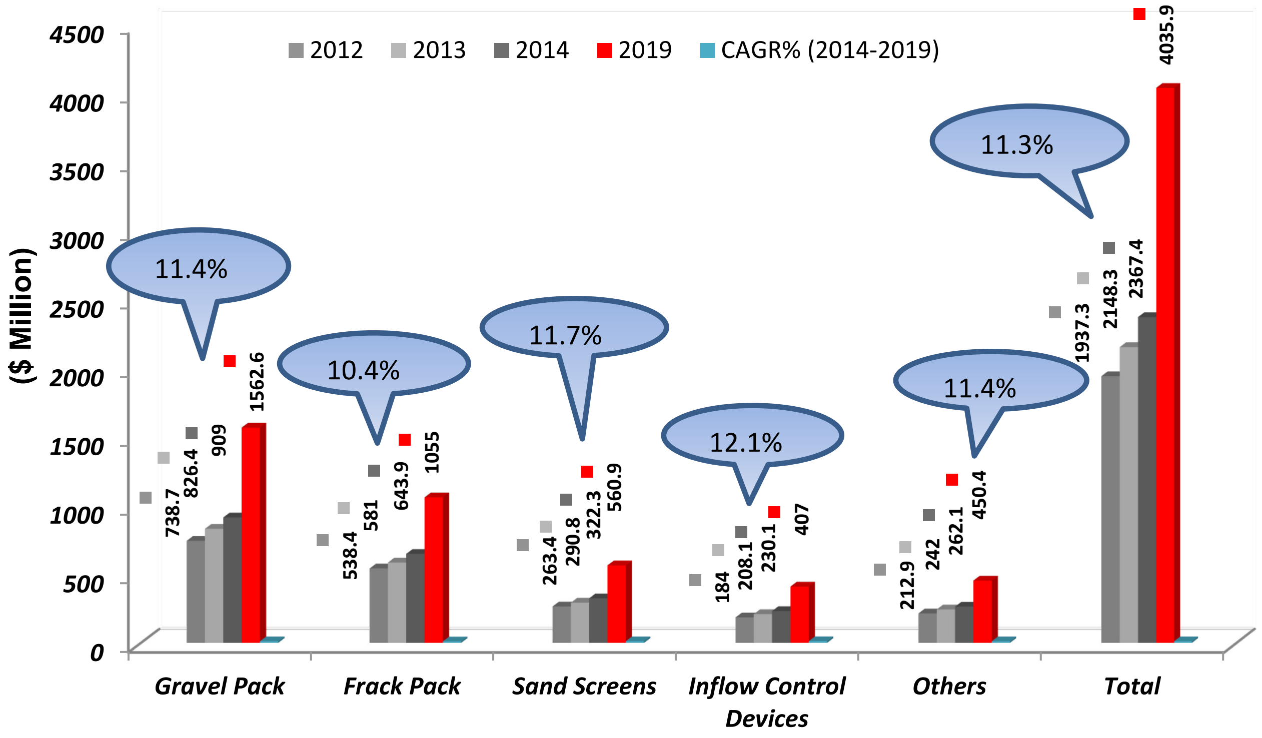


Figure 7-4 Sand control systems market size, by type, 2012-2019 ($ Million) [60]

The global market is led by gravel pack systems at an expected growth rate of 11.4% from 2014 to 2019, followed by frac pack systems with an expected market size of $1,055.0 million by 2019. The market is growing due to high requirement of well completion techniques for higher production rates. The markets for sand screens and inflow control devices are expected to grow from $322.3 million and $230.1 million in 2014 and could reach to $560.9 million and $407.0 million by 2019 respectively.

7.2.1 Gravel Pack Systems Market Size, (2014 to 2019)

As it is shown in Figure 7-5 the global market for gravel pack systems is led by North America with a market share of 36.1%, followed by the Asia-Pacific with 33.3% market share in 2014.

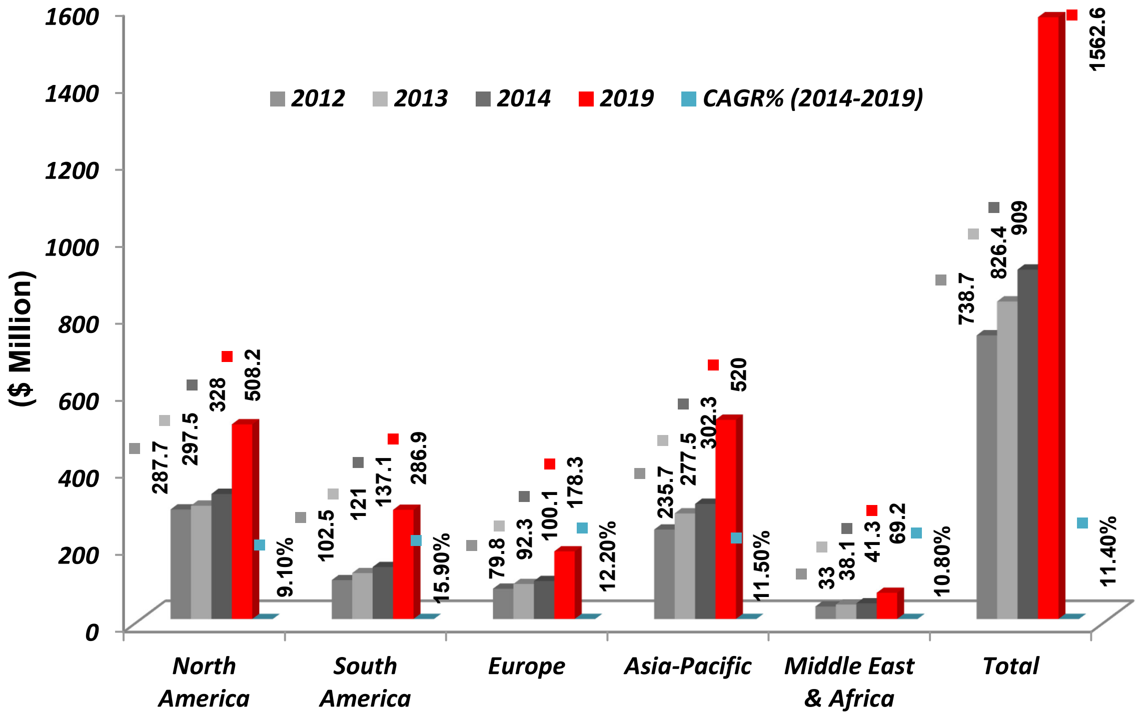


Figure 7-5 Gravel pack market size, by region, 2012-2019 ($ Million) [60]

The gravel pack market is expected to grow at a CAGR of 11.4% from 2014 to 2019. Highest growth could be experienced in South American region due to more number of discoveries in the offshore areas of Brazil and Argentina. The North American region is expected to reach $508.2 million by the next five years. However, it is expected to grow at a moderate CAGR of 9.1% due to the shift in trend from conventional to unconventional wells in the U.S. including the Gulf of Mexico. The European market is expected to rise from $100.1 million in 2014 to $178.3 million by 2019, owning to the increased explorations in Russian, Norwegian markets, and the expected increase in the production market of the U.K. The Asia-Pacific region is expected to lead the gravel pack systems market with a projected market size of $520 million by 2019. This region would replace the current market leader, North America by 2019 due to higher E&P spending by oil & gas operators for drilling new wells, leading to increased oil production in the Asia-Pacific region.

7.2.2 Sand Screens Market Size, (2014 to 2019)

As it is shown in Figure 7-6 the market for sand screens is led by North America with a market share of 49.2%, followed by the Asia-Pacific with 19.9%, and South America with 11.2% respectively in 2014.

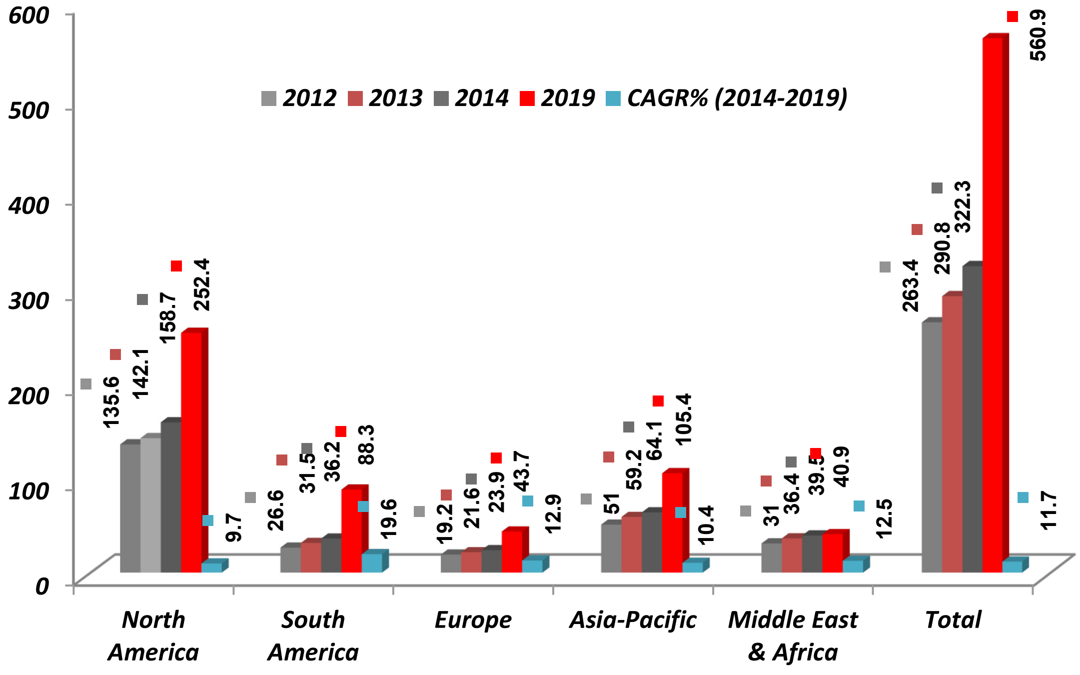


Figure 7-6 Sand screens market size, by region, 2012-2019 ($ Million) [60]

The sand screens market is expected to grow at a growth rate of 11.7%, with leading market share of North America. The Asia-Pacific region is the second largest market for sand screens. Huge investments in E&P activities drive the Asia-Pacific market with market size reaching $105.4 million by 2019 from $64.1 million in 2014. The Middle East and Africa is also expected to grow at a moderate CAGR of 12.5% from 2014 to 2019. Highest growth rate could be experienced by South America due to new discoveries in Brazil.

8 Sand Screens Suppliers

There are so many companies available in sand screens market as suppliers. Some are well known service companies such as Baker Hughes, Halliburton, Weatherford, Schlumberger and some are only manufacturers of sand screens. In Table 8-1 a list of these companies and their products are provided.

Table 8-1 Sand screens suppliers [19]

Photo Key	Supplier / Product Trade Name	Screen/Product Type				
		Wire-Wrapped	Pre-Packed	Shrouded Metal Mesh	Expandable	Other
	3M PETROCERAM (www.petroceram.com)					
1	PETROCERAM and PETROCERAM TT					**CSS**
	ALLOY SCREEN WORKS (www.alloyscreenworks.com)					
	ASW ALPHA ROD BASE	X				
2	ASW DUAL PRE-PACK and DUAL PRE-PACK/TT		X			
	ASW DUAL PRE-PACK/SC		X			
3	ASW PIONEER and PIONEER/TT	X				
4	ASW SAND-BAR			X		
	ASW SLOTTED LINERS					**SL**
	ASW WILDCATTER ALL-WELDED WRAP-ON	X				
	BAKER HUGHES (www.bakerhughes.com)					
	BAKERWELD	X				
	BAKERWRAPXP	X				
	EQUALIZER HELIX ICD					
5	EQUALIZER SELECT ICD					
6	EXCLUDER2000			X		
	EXPRESS				**BPE**	
7	GEOFORM					**SMP**
	SELECTAFLOW II AND SELECTAFLOW III	X				
	SLIM-PAK		X			
	CON.SLOT 2.0 OIL & GAS SCREENS GmbH (www.con-slot.de)					
8	FORMATIONLINK	X				
9	FORMATIONLINK CERAMIC-COATED SCREEN	X				
	DELTA SCREENS (www.deltascreens.com)					
	DELTA DIRECT WRAP-ON	X				
10	DELTAELITE			X		
11	DELTAPAK		X			
	DELTAPORE HP THRU TUBING			X		
12	DELTAWELD	X				

Notes: CSS stands for Ceramic Sand Screen, SL stands for Slotted Liners, BPE for Base Pipe Expansion, and SMP for Shaped Memory Polymer.

Photo Key	Supplier / Product Trade Name	Screen/Product Type				
		Wire-Wrapped	Pre-Packed	Shrouded Metal Mesh	Expandable	Other
	HALLIBURTON (www.halliburton.com)					
	ALL-WELD	X				
	ENHANCED LOW-PROFILE		X			
	EQUIFLOW AUTONOMOUS ICD					
	EQUIFLOW ICD					
	PETROGUARD ADVANCED MESH			X		
14	PETROGUARD MESH DS (DUAL SHROUD)			X		
	PETROGUARD MODULAR SCREEN	X		X		
15	PETROGUARD SHUNT SYSTEM	X		X		
	PETROGUARD SWELL				SFE	
	PETROGUARD WRAP (Direct Wrap)	X				
	POROMAX			X		
	PREMIUM LOW-PROFILE		X			
	H.P. WELL SCREEN (www.hpwellscreen.com)					
	AICV					
16	HP SLOTTED LINER					SL
	MESHLOCK			X		
	POROBOND			X		
17	POROLOCK			X		
18	QFLUX					
	SANDFREE	X				
	SOLIDWRAP	X				
	SLIMPACK		X			
	REGENT ENERGY GROUP (www.regentenergygroup.com)					
	PREMIUM TRS SLOTTED LINERS					SL
19	PREPACKED SLOTTED LINERS					SL
20	SLOTTED LINERS					SL
	SCHLUMBERGER (www.slb.com/transcend, www.absolutect.com)					
	ACCURITE	X				
21	ENDURE / ASSURE			X		
	EXTRACTOR WIRE WRAP	X				
22	TRI-D FACSRITE*					PMD
	TRI-D FACSWAX*					WPMD
	LINESLOT / DOMINATOR DIRECT WRAP	X				
	LINESLOT HIGH RATE GAS	X				
23	MESHFLUX ICD					
24	MESHRITE*			X		
	PREMIUM PORT 3 ICD					
	PACKRITE		X			
25	RESFLOW ICD					
26	RESINJECT ICD					
	TRI-D DIRECTRITE*			X		

Notes: SFE stands for Swellable Filter Expansion, PMD for Premium Metal-mesh Discs, and WPMD for Waxed Premium Metal-mesh Discs.

Photo Key	Supplier / Product Trade Name	Screen/Product Type				
		Wire-Wrapped	Pre-Packed	Shrouded Metal Mesh	Expandable	Other
	SUPERIOR ENERGY SERVICES (www.superiorenergy.com)					
31	COILFLO DB (Diffusion Bonded)			X		TT
	DYNAFLO DB (Diffusion Bonded)			X		
	ECONOFLO			X		SC
32	PROWELD	X				
	PROWELD TOP (Tight On Pipe)	X				
	SLIMFLO		X			
	SUREFLO			X		SC
	UNIFLO ROI					
	TUBULAR PERFORATING MANUFACTURING (www.tpmltd.com)					
	UNISCREEN			X		
	WEATHERFORD (www.weatherford.com)					
	ESS				BPE	
	FLOREG ICD					
	MAXFLO			X		
	MAXFLO-BL			X		
	MAZEFLO	X				SMS
	MICRO-PAK		X			
	ULTRAFLO SLIP-ON JACKET	X				
	ULTRA-GRIP DIRECT WRAP	X				
	ULTRAWELD SLIP-ON JACKET	X				

Notes: TT stands for Thru-Tubing, SC for Special Clearance, and BPE stands for Base Pipe Expansion.

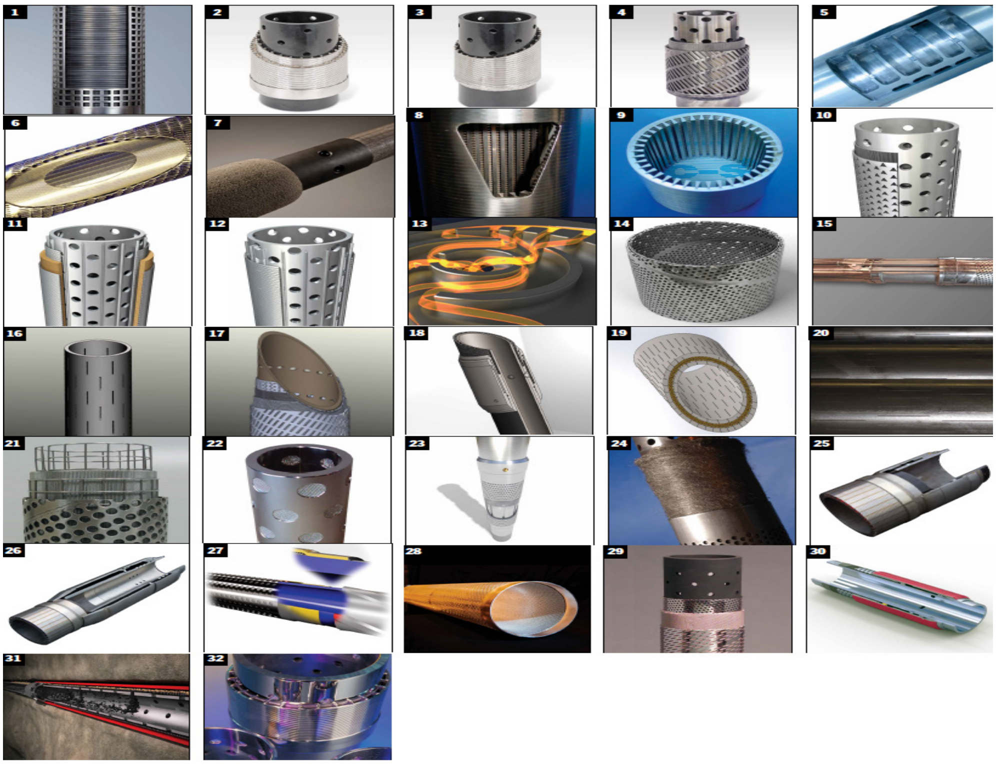


Figure 8-1Sand Screens Products by Type

9 Conclusion

Throughout this master thesis, a comparison between 13 alloys from different material groups (suggested by NACE standards to be used in sweet and sour borehole environments) has been made. These material groups were compared in terms of corrosion resistance (PREN, CPT), Mechanical properties (such as Hardness, Tensile Strength (Yield and ultimate) in annealed and cold work conditions). Furthermore, a detailed overview and the market forecast of sand control systems by type and their applications in onshore and offshore facilities has been discussed. According to the results achieved in this thesis, following conclusions have been made:

- Sand production is a phenomenon that should be expected in both sandstone and carbonate reservoirs, at any given time in their lifetime.
- Temperature and pressure gradients are not fixed values and they have to be tested and measured in each geographical and geological region.
- Alloys 316L, 13Cr and S13Cr must be used only in deaerated, non-H_2S-containing conditions.
- In presence of H_2S, the performance of Alloy 22Cr and 25Cr is highly sensitive to chloride ions.
- Alloy 28 is slightly resistant to SCC from elemental sulphur. Thus, the applications that contain sulphur combined with chlorides and H_2S required further assessments.
- Alloys 825, 2550, C276 are resistant against any level of CO_2 concentration. Alloys 825 and 2550 are only sensitive to H_2S, temperature and high concentration of chloride. Alloy C276 can resist corrosion at all CO_2 and H_2S concentrations, in temperatures below 260°C.
- Key drivers of the Sand Control systems market include increasing number of wells drilled, investments in onshore and offshore areas, wearing and erosion of production equipment, and inefficiency in well production rates and creation of downhole cavities.
- Sand Control systems in the offshore arena are expected to experience a growth rate of 15.1% from 2014 to 2019. This is due to increasing offshore activities in Brazil, Gulf of Mexico, and Australia.
- In the onshore, the market size was around $1,670 million in 2012 and is expected to increase to about $3,228 million by 2019 at a growth rate of 10.4% from 2014 to 2019.
- The gravel pack market leads the Sand Control systems market with a market share of 38.4%, followed by frac pack with 27.2%, and Sand Screens with 13.6% in 2014, globally.

10 References

1. 1999. *Plugging-induced screen erosion difficult to prevent1*. http://images.pennwellnet.com/ogj/images/ogj2/9629jpr06a.jpg (Accessed 30 March 2016).
2. 1999. *Plugging-induced screen erosion difficult to prevent2*. http://images.pennwellnet.com/ogj/images/ogj2/9629jpr06b.jpg (Accessed 30 March 2016).
3. Bellarby, J. 2009. *Well completion design.* Amsterdam, Netherlands, Boston, Mass., Elsevier. (Developments in petroleum science, v. 56).
4. McPhee, C. A., Farrow, C. A. and McCurdy, P. Challenging Convention in Sand Control: Southern North Sea Examples, *SPE International Symposium and Exhibition on Formation Damage Control* .
5. Simangunsong, R., Villatoro, J. J. and Davis, A. K. Wellbore Stability Assessment for Highly Inclined Wells Using Limited Rock-Mechanics Data, *SPE Annual Technical Conference and Exhibition* .
6. William K. Ott, P.E. and Joe D. Woods. 2001. World Oil¹s Modern Sandface Completion Practices.
7. API RP 58 (1995). Recommended Practices for Testing Sand Used in Gravel Packing Operations, American Petroleum Institute (API).
8. E29 Committee. Specification for Woven Wire Test Sieve Cloth and Test Sieves. West Conshohocken, PA, ASTM International.
9. HAVER & BOECKER. *Sieve Analysis of up to 15 kg Sample Weight. HAVER EML 450 digital plus for dry and wet sieving*. http://www.haver-partikelanalyse.com/en/sieve-analysis/haver-ws-tylerr-test-sieve-shakers/haver-eml-450-dp/ (Accessed 7 April 2016).
10. Voelker, C. *Dynamic Light Scattering for particle sizing and measurement of particle size distribution*. http://www.lsinstruments.ch/technology/dynamic_light_scattering_dls/ (Accessed 11 April 2016).
11. Schwartz, D. H. 2013. Successful Sand Control Design for High Rate Oil and Water Wells. *Journal of Petroleum Technology*, Vol. 21, No. 09, pp. 1193–98.
12. Weatherford Co. 2010 - 2011. Weatherford Sand Screen Selector - Open-hole.
13. ISO 17824:2009. Petroleum and natural gasindustries--Downhole equipment--Sand screens. 2009. Geneva, Switzerland.
14. Xie, J. Slotted Liner Design Optimization for Sand Control in SAGD Wells, *SPE Thermal Well Integrity and Design Symposium* .
15. Harrison, D. J., Johnson, M. H. and Richard, B. Comparative Study of Prepacked Screens, *SPE California Regional Meeting* .
16. 2015. *Pre-packed Screen, the Most Effective Screen in Oil and Gas Wells*. http://www.wellscreen.org/well-screen/pre-packed-screen.html (Accessed 12 April 2016).
17. Evans, B. and Syed, A. Effect of Acid on Resin Coated Gravel in Prepacked Screens, *SPE Formation Damage Control Conference* .

18. 2015. *Pre-packed Screen, the Most Effective Screen in Oil and Gas Wells*. http://www.wellscreen.org/well-screen/pre-packed-screen.html (Accessed 12 April 2016).
19. William K. Ott, P.E. and Joe D. Woods - Graphics by: Steve Stanley Design. 2014. *January 2014 Sandface Completions Guide - Sand Exclusion Devices, ICD Products and Suppliers plus Sandface Completions and Gravel/Proppant Data.* 7903 Alamar, Houston, TX 77095 USA.
20. Schlumberger. 2004. *Schlumberger Premium Screens*.
21. Mohd Ismail, I. and Geddes, M. W. 2014. Fifteen Years of Expandable-Sand-Screen Performance and Reliability. *SPE Drilling & Completion*, Vol. 29, No. 02, pp. 141–49.
22. Hembling, D., Lauritzen, E., Phillips, J., Rabba, A., Jones, C., Beare, S. P., Morgan, Q. and Cameron, J. A. A Comprehensive Study on the Effect of Compliance on Productivity, *SPE Annual Technical Conference and Exhibition* .
23. Hamid, S. and Ali, S. A. Causes of Sand Control Screen Failures and Their Remedies, *SPE European Formation Damage Conference* .
24. *SPE Asia Pacific Oil and Gas Conference and Exhibition*. 2000.
25. Herbert Hofstätter. 2015. *Bio Enhanced Energy Recovery – BEER®Ein nachhaltiger Beitrag zur Versorgungssicherheit mit Kohlenwasserstoffen*.
26. Tiffin, D. L., King, G. E., Larese, R. E. and Britt, L. K. New Criteria for Gravel and Screen Selection for Sand Control, *SPE Formation Damage Control Conference* .
27. Saucier, R. J. 2013. Considerations in Gravel Pack Design. *Journal of Petroleum Technology*, Vol. 26, No. 02, pp. 205–12.
28. *SPE International Conference and Exhibition on Formation Damage Control*. 2016.
29. King, G. E., Wildt, P. J., O&apos and Connell, E. Sand Control Completion Reliability and Failure Rate Comparison With a Multi-Thousand Well Database, *SPE Annual Technical Conference and Exhibition* .
30. Ellis, R. C. 2013. An Overview of Frac Packs. A Technical Revolution (Evolution) Process. *Journal of Petroleum Technology*, Vol. 50, No. 01, pp. 66–68.
31. Heidersbach, R. 2011. *Metallurgy and corrosion control in oil and gas production.* Oxford, Wiley. (Wiley series in corrosion).
32. Denis Brondel, Randy Edwards, Andrew Hayman, Donald Hill, Shreekant Mehta, Tony Semerad. 1994. Schlumberger oilfield review - Corrosion in oil industry -.
33. Fontana, M. G. and Greene, N. D. 1978. *Corrosion engineering.* 2nd ed. New York, London, McGraw-Hill. (McGraw-Hill series in materials science and engineering).
34. American Petroleum Institute. ANSI/API-RP14E.
35. Lyons, W. C. and Plisga, G. J. 2005. *Standard handbook of petroleum & natural gas engineering.* 2nd ed. Oxford, Gulf Professional.
36. OAKLEY STEEL Limited. *WHAT IS HIC RESISTANT STEEL PLATE?* http://www.oakleysteel.co.uk/pressure-vessel-steel-plate/hic-resistant-steel-plate.
37. *International Petroleum Exhibition and Technical Symposium*. 1982.
38. Retrieved 2013. Greenhouse Gas R&D Programme. (2009, November 1). 4 Impact of CO2 on wellbore integrity. Global Carbon Capture and Storage Institute.,

39. Sridhar Srinivasan (CLI International Inc.) | Russell D. Kane. 1996. Prediction of Corrosivity of CO2/H2S Production Environments, NACE-96011.
40. Iranian Petroleum Standard (1997). Corrosion control in design. http://igs.nigc.ir/IPS/tp/e-tp-760.pdf (Accessed 1 May 2010).
41. W. R. Revie. 2008. Corrosion and Corrosion Control , Wiley -Interscience, 2008.
42. Univ.-Prof. Dipl.-Ing. Dr.mont. Markus Oberndorfer. *Metallurgie und Korrosion*.
43. Global Energy Network Institute. Geothermal Energy in IranGeothermal Prospect Area in Iran.
44. GeologyIn. *Geothermal gradient*. http://www.geologyin.com/2014/12/geothermal-gradient.html.
45. *SPE Latin America and Caribbean Petroleum Engineering Conference*. 2014.
46. Department of Geology San Jose State University. 1999. *Department of Geology San Jose State University*. http://oceansjsu.com/105d/exped_briny/9.html.
47. Iranian Petroleum Standard (2010). Engineering Standard for Corrosion Considerations in Material Selection.
48. D. E. Milliams and R. N. Tuttle (ed.). 2003. *A new international standard for metallic materials for use in oil and gas production in sour environments. ISO 15156/NACE MR0175 - NACE 03090*.
49. NACE MR0175/ISO 15156-3 (2015). Petroleum and natural gas industries — Materials for use in H2S containing environments in oil and gas production — Part 3: Cracking resistant CRAs (corrosionresistant alloys) and other alloys.
50. Myer Kutz. 2002. *Handbook of Materials Selection*.
51. Hilders, O. A., Zambrano, N. and Caballero, R. 2015. Microstructure, Strength, and Fracture Topography Relations in AISI 316L Stainless Steel, as Seen through a Fractal Approach and the Hall-Petch Law. *International Journal of Metals*, Vol. 2015, No. 3, pp. 1–10.
52. Chianpairot, A., Khamsuk, P., Wongpinkaew, K., Kaewkumsai, S. and Viyanit, E. 2015. Failure of Alloy 20 nozzles used for spraying sulfuric acid in an incineration furnace. *Engineering Failure Analysis*, Vol. 49, pp. 113–21.
53. Papavinasam, S. 2014. *Corrosion control in the oil and gas industry.* London, Waltham, Mass., Gulf Professional Pub.
54. George Vander Voort. *Grain Size Measurement: The Jeffries Planimetric Method*. http://vacaero.com/information-resources/metallography-with-george-vander-voort/1269-grain-size-measurement-the-jeffries-planimetric-method.html.
55. Bruce D. Craig and Liane Smith. Corrosion Resistant Alloys (CRAs) in the oil and gas industry - selection guidlines update, 3rd Edition, Technical Series N° 10073.
56. P Woollin. *Developments in fusion welding of stainless steels*. http://www.twi-global.com/technical-knowledge/published-papers/developments-in-fusion-welding-of-stainless-steels-january-1994/ (Accessed 1994).
57. Hervé MARCHEBOIS, Jean LEYER, Bertine ORLANS-JOLIET. 2007. NACE INTERNATIONAL CORROSION 2007. SSC Performance of a SUPER 13% Cr Martensitic STAINLESS STEEL for OCTG: Three-dimensional Fitness-fot-purpose

Mapping according to PH2S, pH and chloride content, PaperNo. 07090, Paper No. 07090.

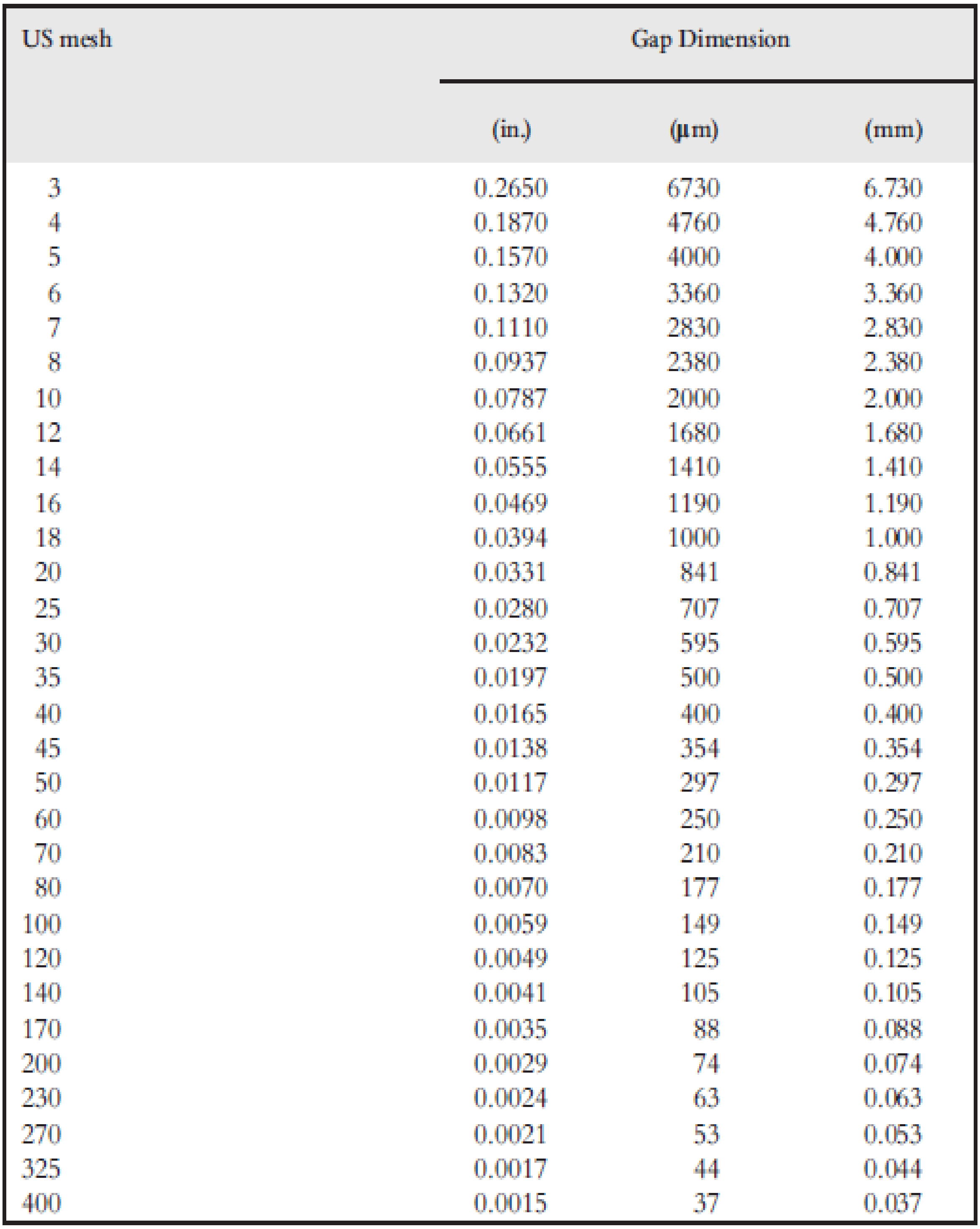
58. www.matweb.com. *Material Property Data*. www.matweb.com.
59. NeoNickel. Alloy Performance Guide.
60. MARKETSANDMARKETS (ed.). 2015. *Sand Control System Market. By Type (Gravel pack, Frack pack, Sand screens, ICD, and Others) Application (ONSHORE&OFFSHORE), & Region*. Global Trends & Forecast to 2019, www.marketsandmarkets.com.

Nomenclature

σ_v	Principal vertical stress
σ_H	Principal horizontal stress, maximum
σ_h	Principal horizontal stress, minimum

A. Appendices

Mesh sizes and gap dimensions chart



US mesh	Gap Dimension		
	(in.)	(µm)	(mm)
3	0.2650	6730	6.730
4	0.1870	4760	4.760
5	0.1570	4000	4.000
6	0.1320	3360	3.360
7	0.1110	2830	2.830
8	0.0937	2380	2.380
10	0.0787	2000	2.000
12	0.0661	1680	1.680
14	0.0555	1410	1.410
16	0.0469	1190	1.190
18	0.0394	1000	1.000
20	0.0331	841	0.841
25	0.0280	707	0.707
30	0.0232	595	0.595
35	0.0197	500	0.500
40	0.0165	400	0.400
45	0.0138	354	0.354
50	0.0117	297	0.297
60	0.0098	250	0.250
70	0.0083	210	0.210
80	0.0070	177	0.177
100	0.0059	149	0.149
120	0.0049	125	0.125
140	0.0041	105	0.105
170	0.0035	88	0.088
200	0.0029	74	0.074
230	0.0024	63	0.063
270	0.0021	53	0.053
325	0.0017	44	0.044
400	0.0015	37	0.037

Figure A-1 Mesh sizes and gap dimensions [3]

B. Appendices

Schlumberger premium screens specifications [20]

Premium Screens Specifications

Pipe Size (in. [cm])	Weight (lbm/ft)	Product OD (in. [cm])	Product Weight (lbm/ft)	Hole Size (in. [cm])	Number of Holes per ft	Tensile Load (lbf [N])	Torque Load (ft-lbf [N-m])	Collapse Pressure (psi [kPa])	Bending Limit (°/100 ft)	Burst Rating (psi [kPa])
2.375 [6.0]	4.6	3.300 [8.4]	8.3	0.375 [1.0]	80	58,446 [259,981]	2,460 [103.7]	9,323 [64,282]	45	1,548 [10,673]
2.875 [7.3]	6.4	3.800 [9.7]	10.7	0.375 [1.0]	93	82,823 [368,415]	4,262 [179.6]	8,839 [60,945]	45	1,332 [9,184]
3.500 [8.9]	9.2	4.420 [11.2]	14.2	0.375 [1.0]	120	115,926 [515,665]	7,303 [307.7]	8,339 [60,945]	45	1,135 [7,826]
4.000 [10.2]	11.0	4.920 [12.5]	16.6	0.500 [1.3]	80	152,710 [679,288]	11,156 [470.1]	6,699 [46,190]	45	1,014 [6,992]
4.000 [10.2]	11.6	4.920 [12.5]	17.2	0.500 [1.3]	80	165,261 [735,118]	11,931 [502.8]	7,354 [50,706]	45	1,014 [6,992]
4.500 [11.4]	11.6	5.440 [13.8]	17.8	0.500 [1.3]	80	172,523 [767,421]	14,467 [609.6]	5,002 [34,489]	45	914 [6,302]
4.500 [11.4]	12.6	5.440 [13.8]	18.8	0.500 [1.3]	80	185,823 [826,582]	15,438 [650.6]	5,908 [40,736]	45	914 [6,302]
5.000 [12.7]	15.0	5.940 [15.1]	21.7	0.500 [1.3]	93	222,545 [989,829]	20,587 [867.5]	5,635 [38,853]	45	834 [5,750]
5.000 [12.7]	18.0	5.940 [15.1]	24.7	0.500 [1.3]	93	267,163 [1,188,400]	24,077 [1,014.6]	8,153 [56,215]	45	834 [5,750]
5.500 [14.0]	17.0	6.450 [16.4]	24.3	0.500 [1.3]	107	249,751 [1,110,948]	25,616 [1,079.5]	4,826 [33,275]	45	766 [5,282]
5.500 [14.0]	20.0	6.450 [16.4]	27.3	0.500 [1.3]	107	292,270 [1,300,082]	29,366 [1,237.5]	6,786 [46,789]	45	766 [5,282]
6.625 [16.8]	20.0	7.580 [19.3]	28.6	0.500 [1.3]	120	295,828 [1,315,909]	37,423 [1,577.0]	2,728 [18,810]	45	463 [3,192]
6.625 [16.8]	24.0	7.580 [19.3]	32.6	0.500 [1.3]	120	356,849 [1,587,343]	44,283 [1,866.1]	4,515 [31,131]	45	463 [3,192]

Note: Tensile, torque, collapse, and bending are based on base pipe with 80,000 psi [551,600 kPa] yield and 10% perforations.
Burst is based on shroud. Screen does not lose sand control at the point of shroud yielding.
Safety factor for bending and burst rating: 2
Safety factor for other ratings above: 1.2