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RESERVOIR STIMULATION BY ACIDIZING IN AL TAWILA FIELD BLOCK-14

A PROJECT SUBMITTED IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE OF BACHELOR OF SCIENCE IN OIL AND GAS ENGINEERING

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APPROVAL

This is to certify that the project Entitled **RESERVOIR STIMULATION BY ACIDIZING IN AL TAWILA FIELD BLOCK-14** has been read and approved for meeting part of the requirements and regulations governing the award of the Bachelor's Degree of Engineering (Oil and Gas), Emirates International University, Sana'a, Yemen.

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DECLERATION

We hereby declare that this Bachelor's Project is the result of our own work, except for quotations and summaries that have been duly acknowledged.

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ABSTRACT

Identifying the type of damage in any formation has a major impact on the development of hydrocarbon formation productivity. The damage needs to be dealt with using the proper and most successful treatment process in order to maintain a desirable production rate. Due to the importance of treatment in oil and gas industry, this study is focusing on one mean of treatment which is matrix stimulation. The analysis and calculations will be conducted in on of Al-Tawila wells. In particular, the study will demonstrate and show how to apply an acid treatment on a specific formation by careful selection of acid type and the additives to be added to the acids. For accurate and successful implementation, the petro-physical and chemical characteristics of the formation of interest should be analyzed alongside other important characteristics such as the formation temperature, pressure, depth and the well deviation data. After taking all the previous characteristics into consideration, the acid mixtures for each stage of the acidizing will be selected with respect to the type of additives to be used and their concertation. All in all, different procedures and measurement need to be taken to check the success of the treatment.

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API	American Petroleum Institute
BBL	Barrel of Oil
BOPD	Barrel of Oil Produced
BWPD	Barrel of Water Produced

C°	Degree Celsius
CFA	Closed Fracture Acidizing
CP	Centipoise
CST	Centistokes
CT	Coiled Tubing
CTU	Coiled Tubing Unit
EUR	Enhanced Ultimate Recovery
F°	Fahrenheit
FT	Feet
GM/CC	Gram Per Cubic Centimeter
LQ	Lower Qishn
MA	Mega Annum (Millions of Years)
MD	Millidarcy
MMBBL	Million Barrel of Oil
PDRY	People’s Democratic Republic of Yemen
PSI	Pound-force per Square Inch
PSIA	Pound-force per Square Inch Atmospheric
PSIG	Pound-force per Square Inch Gauge
STB	Stock Tank Barrel

CHAPTER ONE

1. INTRODUCTION

1. Introduction

Having a great deal of knowledge about the structure of the earth, reservoirs more specifically, helps us in the future whenever we need to treat the formation due to the rapid decline in production alongside any other issues that affect the formation like, formation damage (positive skin effect), rock expansion, water influx, sand production and so on. Moreover, the pressure of any formation declines as a result of producing for a considerable period of time, it could take five, ten or more years depending on the formation deliverability.

Reservoir stimulation is one of the main treatments applied on the producing wells whenever there is a damage. The main purpose of stimulation is to enhance productivity and maximize recovery in oil and gas wells whenever their performance is undesired or decreased due to any kind of damage.

Before knowing what is Reservoir Stimulation? We must know when we decide to use it instead of the other enhancement techniques. Moreover, another question is what drives these large quantities of oil to the surface? The answer to this question is, pressure, or more precisely, the pressure difference between the bottom of the well and the surface. Because the pressure at the wellhead is less than pressure at the bottom, the oil flows from the high pressure in the bottom well to the low pressure, which represents the wellhead on the surface. If this condition does not exist, the flow of the oil will naturally stop. Indeed, there are several forces responsible for pressing the bottom of the well. More specifically, there are four types of pressure: layer pressure, rock pressure, stock pressure and total pressure. Therefore, the pressure is what lifts the oil to the surface and as it lies on the presence of other lift forces that lift the oil to the surface.

Dissolved gas drive, water drive, gas cap drives. These forces are called primary drive, in which the initial production. The use of stimulation is recommended when the pressure in the primary drive mechanisms inside the well drops to levels that make primary drive less effective.

Reservoir stimulation techniques are applied on a regular basis to enhance the property value by the faster delivery of the petroleum fluid and/or to increase ultimate economic recovery. Matrix stimulation and hydraulic fracturing are intended to remedy, or even improve, the natural connection of the wellbore with the reservoir, which could delay the need for artificial lift. This chapter outlines stimulation techniques that help managing and optimizing reservoir development. Understanding stimulation requires understanding the fundamental issues of petroleum production and the position and applicability of the process.

1.2. Aims and objectives

1.2.1. Aims

1- Perform a stimulation treatment (Acidizing) on the Tawila field.
2- Identify the consequence of the acidizing treatment performed on the Formation.

1.2.2. Objectives

1- Determine the proper acidizing process to perform.
2- Appropriate selection of type and quantity of acid with the right additives and diversion technique.
3- Observe the outcome of the simulation process.

1.3. Problem Statement

Understanding the nature of the production is an essential issue in the oil and gas industry. It is vital to maintain the production at a profitable rate as much as possible and try to overcome any circumstances that could have a negative impact on the production rate. Solid particles can be a serious problem as they tend to block the flow channels alongside other heavy liquids like bitumen. As a result, some stimulation techniques had to be invented and then applied to solve this problem. Acid stimulation is the main process that is used in order to unplug or remove the flow-blocking substances. Because of its importance and contribution to the petroleum industry in general and the production rate more specifically, acid stimulation will be the main focus of the study.

1.4. Research Question

What is Acidizing (Acid Treatment) and what are its applications in the petroleum industry?

1.5. Significant of the Research

The study of this research will focus on the treatment of the formation by increasing Production rate, assisting in formation pressure maintenance, and recovering produced fluids at maximum level.

1.6. Scope of the Research

The Tawila field is the scope of this research and only one well is taken into consideration which is (Tawila 70).

1.7. Al-Masila Block-14

Al-Masila Block-14, located in the Hadhramaut region in the east-central Republic of Yemen, was operated by Canadian Nexen Petroleum Yemen. It is an irregular shaped concession covering 1,257 km^2 of area and 44% of Nexen's overall production comes from the Masila Block-14. Moreover, block-14 is considered to be the second biggest block in Yemen. The main reservoirs in the block are (Qishn Clastic, Saar Carbonate, Basial Sand, Madbi Carbonate, in addition to the basement rock)

Oil was first discovered in late 1990, commerciality declared in late 1991. Oil production began in July 1993. In General, it contains about 19 fields (Camaal, North Camaal, Sunnah, North-East Sunnah, Heijah, Hemiar, South Hemiar, West Hemiar, Tawila, Haru, Nazeia, Bainoon, Qataban & South-East Qataban, North-East Camaal, Ressib & South Rassib, Narr, Dais, Dahban & Gabal-Isbeel, Raydah) with one billion barrel of oil as a reserve and an average production of 58627 BOFD. Furthermore, block-14 contains 56 pools, and the total number of drilled wells until Dec 31, 2010 was 639 wells, of them 274 producers, 122 injectors, 6 disposals, and 2 observations and 90% of the production is produced from the Qishn layer. Additionally, the Block belongs to the Jurassic to lower Cretaceous age. The block is connected with ASShihr export terminal in Hadhramaut and the pipeline length is estimated to be 138 kilometers with a 24 inches diameter.

The latest reserves evaluation for Al-Masilah Block 14 as of Dec 31, 2010 yields total 1P (proved) Stock Tank Oil Originally in Place (STOOIP) of 2,251 MMbbl and Estimated Ultimate Recoverable (EUR) oil reserves of 1,092 MMbbl, a 2P (proved + Probable) STOOIP of 2,356 MMbbl and EUR of 1,093 MMbbl and 3P (proved + Probable + Possible) STOOIP of 2,715 MMbbl and EUR of 1,095 MMbbl.

At the end of December 2010, the annualized average daily production rate collectively for all block fields was 70,336 BOPD and 1,917,357 BWPD with average water cut 96.5%, and total cumulative oil production from the Block is 1,073,588,574 bbl as of Dec 31, 2010.

1.7.1. Al-Tawila Field:

This study will be conducted on the Tawila field that was discovered in 1992 then the production started in 1993. The Tawila field has 184 wells 118 of them are producers and 25 are injectors. The field produce 17264.1 barrel of oil per day and 427852.2 barrel of water and has an average pressure of 179 psig. The main production zones are Upper-Qishn, S1A, S2 and S3. Additionally, the cumulative production until 2011 was 355,952 Mbbl from an estimated STOOIP of 640,221 Mbbl most of it is from S2 zone.

1.7.2. Reason for Studying Al-Tawila Field:

Based on some estimations done in 2012, the remaining oil in place in the Tawila field was 28990 MMbbl of proven oil reserve from a total of 387110 MMbbl of proven oil that can be produced of the total reserve of 667561 MMbbl of oil. This information indicates the need for a stimulation process as the remaining oil value has decreased to a low level alongside the drop in the production rate. Furthermore, acid stimulation can be a good candidate to improve the production rate and reduce any formation damage.

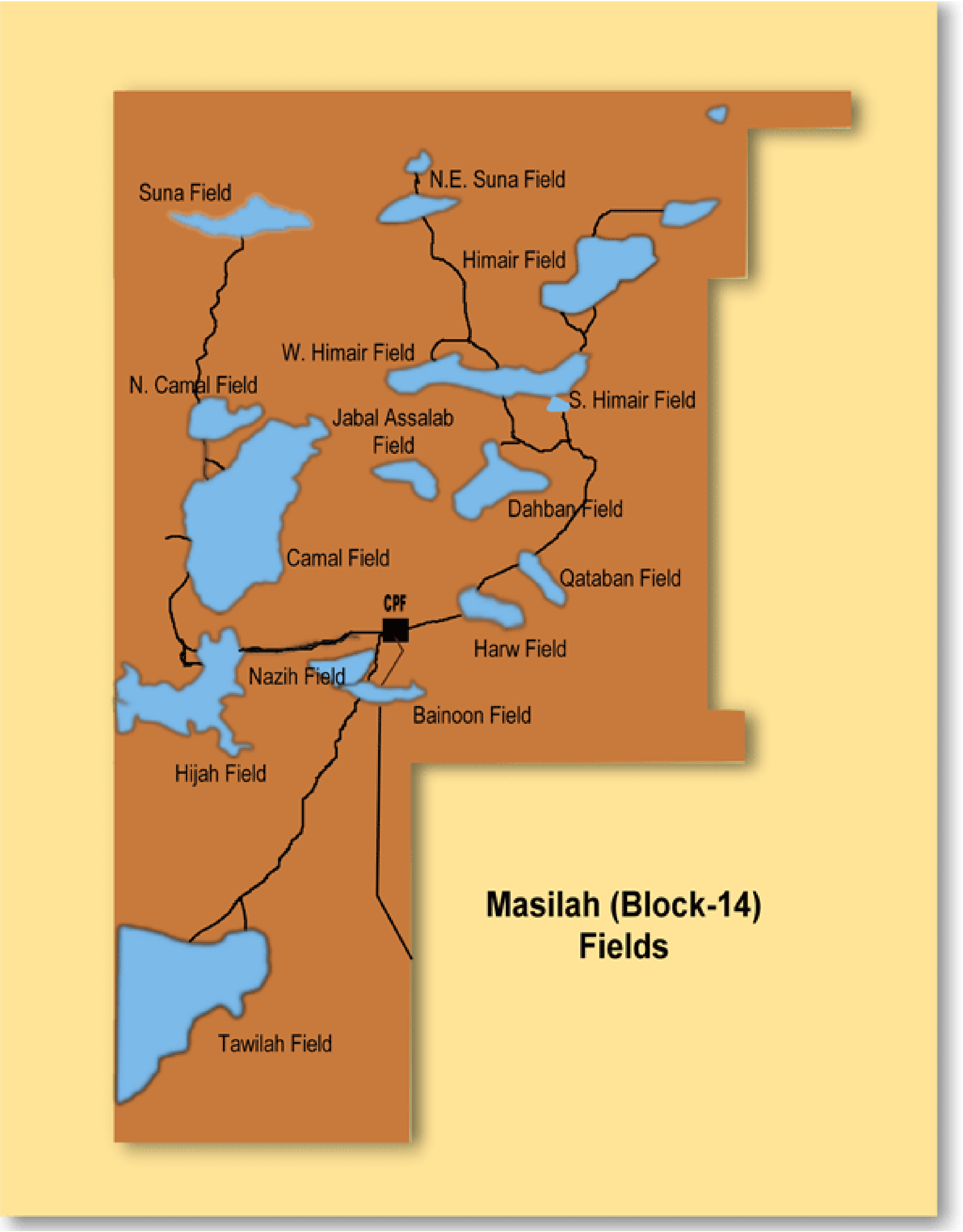


Figure 1-1 Masila block-14 main fields

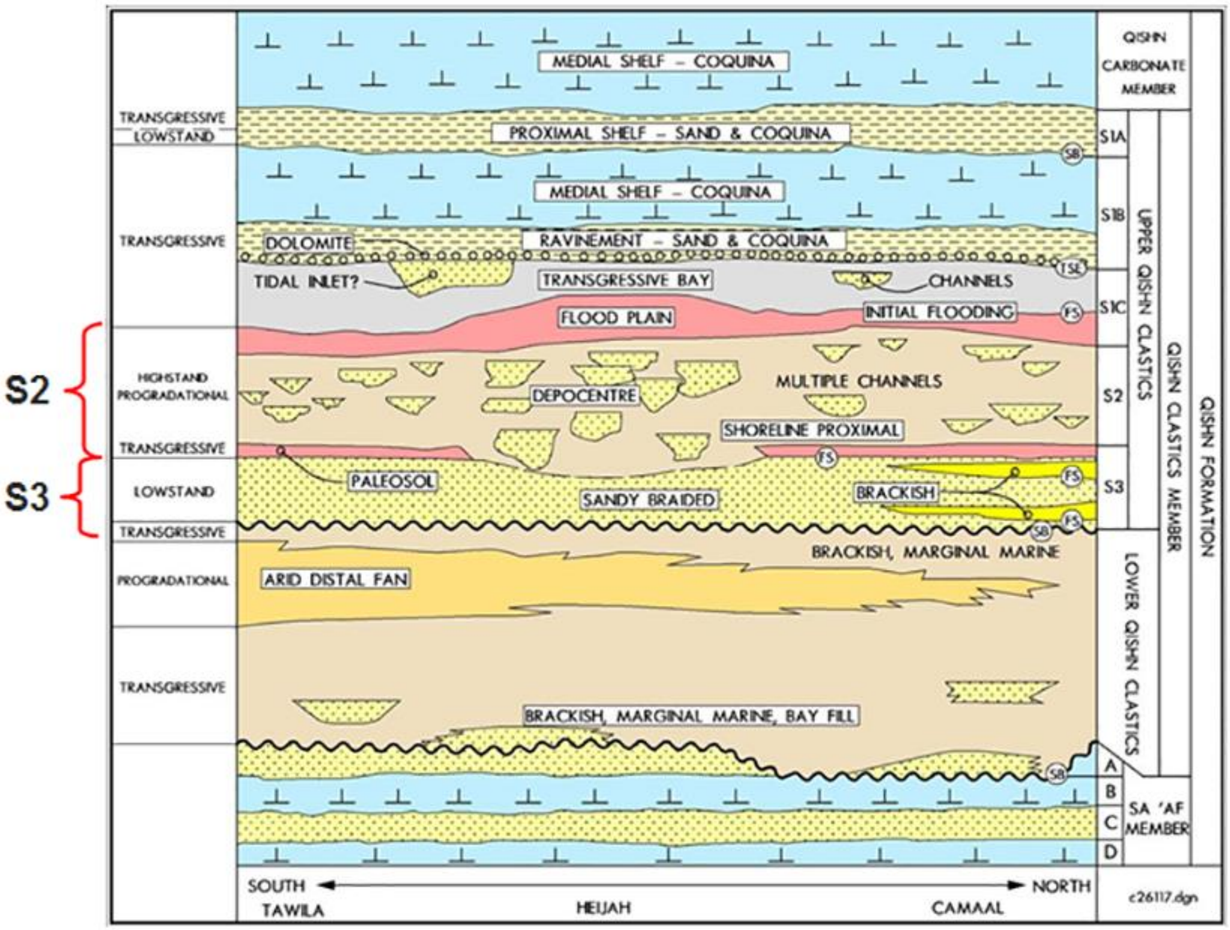


Figure 1-2 Geological Structure and Depositional Environment of Block-14

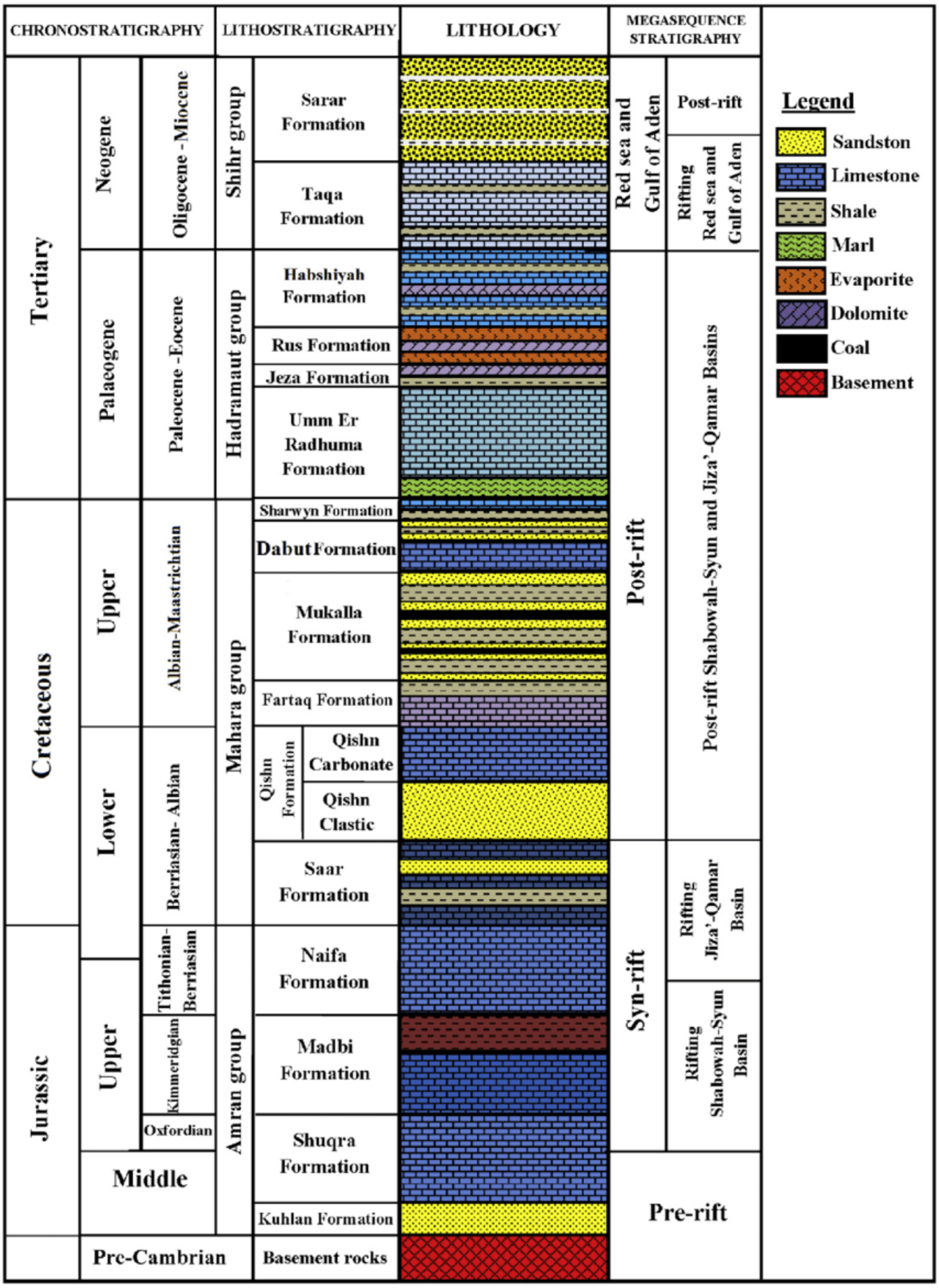


Figure 1-3 Lithostratigraphy Section of Masila Block-14

1.8. Geology of Yemen

1.8.1. Geology, Topology and Terrain

Situated on the southern tip of the Arabian Peninsula, Yemen is a country with a diverse landscape of mountains, plains, and deserts. It covers 203,849 square miles (527,970 square kilometers) including 112 islands.

It also shares borders with Saudi Arabia (1,458 km of borderlines) and Oman (288 km of borderlines). Yemen has 1,906 km of coastline. Yemen also claims 12 naval miles of territorial seas, and an exclusive economic zone of 200 naval miles. This country includes the Red Sea Islands; the Socotra Archipelago islands of Socotra, Abd al Kuri, Samhah and Darsa; the former Yemen Arab Republic (YAR or North Yemen), and the former People's Democratic Republic of Yemen (PDRY or South Yemen) .

1.8.2. Climate:

The climate varies with elevation. The coast is hot and humid throughout the year. The central highlands, with villages at 10,000 feet (3,048 meters), experience an average annual high temperature of 70 F° (21 C°). Average Daily Temperatures in January: 13.9 C°/57 F°; in July: 21.7 C°/71 F°. The climate in Yemen is mostly desert. Although it is hot and humid along the coastal sections, Yemen has an extraordinarily hot, dry and harsh desert in the east. Yemen is temperate in the western mountains which are affected by seasonal monsoons. Monsoon rains may occur from April to August and from November to January. Rainfall is scarce in the coastal desert regions, but runoff from higher elevations and a series of small dams and channels help support some crops. Mountainsides in the arable highlands are terraced to increase the area suitable for cultivation. Forests once covered the highlands, but overgrazing and logging have almost eliminated them. Excluding its coastal waters, Yemen has no permanent body of open water.

The average annual rainfall in Yemen is 508mm/20. Precipitation in Yemen is strongly influenced by relief and consequently varies considerably from place to place. Meteorological observations were made by J. E. Hasen, engineer, and Dr. Carlo Toffolon, then personal physician to the Imam, at Sana'a and Ta'izz, from 1942 to 1944. According to their observations at Ta'izz, the number of rains ranges from 90 to 160 per year, and annual precipitation ranges from 450 to 700 millimeters. Rainfall may exceed 50mm in a single torrential shower. Two rainy periods are distinguished at Ta'izz: (1) the most important period, in which precipitation may exceed 600mm, extends from April to May, or in some years, to June, and (2) a shorter period in which rain falls mostly during August and September. West winds predominate during the rainy seasons. At Sana'a annual precipitation ranges from 200 to 500 mm (60 to 90 showers) and also falls largely within two periods: (1) April to May and (2), the most important, from the later part of July through the first half of August. Clouds generally gather on the west slopes of the main massifs and cause very heavy rainfall which accounts for the erosive actions of the valleys, and the number of local springs. The greatest rainfall occurs in the south, central and western highlands and feeds innumerable valleys which, like the terraced mountainsides, are heavily cultivated. A short monsoon in April and May alternates with a heavier monsoon in July and August, but the remainder of the years features sunny days.

Yemen is covered with rocks whose ages date back to an era prior to the Cambrian era, about 3 billion years ago. Geologically speaking, Yemen composes part of the Arabian Shield within the larger framework of the Arabian-Nubian Shield.

The basement rocks of Yemen are some of the oldest structures dating back to about 3 billion years. Magmata rocks, gneiss and schist rocks represent such structures. These structures appear as belts extending for tens to hundreds of kilometers as ancient areas separating the small sheets which joined together and formed the Arab-African Shield. These rocks spread basically in two areas: the northern-southern area (that is, Sa'adah governorate) and the western-eastern plateau (that is, Ma'reb-Al-Baidha) along with the east of Al-mukalla. The basement rocks of Yemen represent the southern extension of the Arabian Shield, is of Paleoproterozoic to Neoproterozoic age. Yemen has identified five terranes, which can be correlated with the eastern margin of the Arabian Shield in Saudi Arabia and with northern Somalia. These include Paleoproterozoic to Neoproterozoic gneissic terranes and Pan-African island arc terranes and joint zones. These are the Afif, Abas and Mahfid terranes (gneiss terranes) and Al-Bayda and Mukalla terranes (arc terranes). The Basement of Yemen provides the link between the arc collage of the Arabian Shield and the gneissic Mozambique belt of east Africa. In the Upper Neoproterozoic constitution of the shape of the Arabian plate has commenced, so that in Yemen a transitional stage between the basement and platform was development and evidenced by the deposition of folded sediments of the Ghabar Group (Infracambrian). Similar subsurface Infracambrian deposits are known from Qinab-1 well (southern flank of the Rub' Al-Khali basin), which are defined formally as Qinab Group. The Precambrian basement rocks in Yemen comprise metavolcanic, metasedimentary, gneiss and migmatite belts produced in arc environments intruded by post tectonic granites and granodiorites. These are found throughout western Yemen from the northwest (Sa'dah - Al Jawf) and southwest areas (Marib-Al-Bayda), in addition to small outcrops in south of Tai'zz and west of al Mukalla. The oldest known rocks in Yemen occur in the Al Bayda terrane which contains late Archaean aged (Sm-Nd: 2700-2900 Ma) gneisses, amphibolite dykes and granites.

Sedimentary Rocks: The oldest rocks of Yemen's sedimentary structures go back to the prime Proterozoic Eon. Such rocks are represented by Ghabar and Qinab groups which have sandstones and limestones. Also the types of the sedimentary rocks–the sandstones, limestones and the mudstones–cover big areas forming the surfaces and basins in Yemen. Most of these rocks are of the second and third geological eras. An exception is the sandstones of Wajid and the mudstones of Akbarah, located at the western-northern area of Yemen (that is, Sa'adah); these rocks were formed in the first geological era.

- **Sedimentary Rocks in Yemen comprise the following:**

Paleozoic Sediments: 1. Ghabar Group (Infra-Cambrian-Earliest Paleozoic): Sandstone limestone, silt, gypsum. 2. Qinab Group (Infra Cambrian-Lowest Cambrian): Volcano-sedimentary succession consisting of dolerite, sandstone, silty shale and tuff. 3. Wajid Formation (Cambrian - Carboniferous): Quartz sandstone. 4. Akbarah formation (Late Carboniferous-Permian): Tillite (pebbles & boulders of basement rocks), shales, mudstones, sandstones and siltstones.

Mesozoic Sediments: 1. Kuhlan Formation (Lower-Middle Jurassic): Sandstones, thin claystone and siltstone interbeds. 2. Amran Group (Middle Jurassic-Lower Cretaceous): Carbonate marl/shale with evaporitic succession. 3. Tawilah Group (Cretaceous): Sandstone with siltstone, marl, and shale, often interbedded with sandstone and also forming distinct marl or shale intervals and with generally persistent limestone-marl clasts. 4. Mahra Group (Cretaceous): Limestone, marl, and shale, often interbedded with sandstone.

Cenozoic Sediments: 1. Hadramawt Group (Paleocene-Middle Eocene): Dolomite, shale, limestone with chalk and dolomite, marl, papery shale, bedded gypsum, and alternating sand stone and claystone. 2. Majzir Formation (Paleocene-Lower Eocene): A shallow marine-littoral sandstone succession. 3. Shihr Group (Oligocene-Pliocene): Conglomerate, sandstone, silt, limestone and gypsum.

Volcanic Rocks: The formation of the Red Sea’s basin in the third eon was associated with the process of regional uplifting of the western areas of Yemen in the early Eocene Epoch. This was through interval volcanic activities; the highest of which was in the Oligocene and Miocene epochs. Volcanic eruption reoccurred at the beginning of fourth era. Such volcanic operations resulted in the formation of Yemeni volcanic: acid rocks such as rhyolite, Ignimbrite; volcanic glass; and middle and basic rocks like the basalt and andalusite. During the volcanic activities and in the middle of the third eon, there was the formation of overlapped granite structures, injected in different types of rocks; most of which include A’mran group, Al-Tawilah rock group, the rocks of Yemen’s volcanic and basement rocks. Volcanic and Intrusive Rocks: The was a time of Regional uplift occurred in western Yemen in the Paleocene/Eocene as evidenced by intermittent volcanic activity commencing in the Early Eocene which culminated in Oligocene-Miocene times with extensive extrusive and plateau flood basalt eruptions forming the Yemen Volcanic Group. This comprises an older trap series and younger Volcanic Series. These series include the whole spectrum of basaltic lithologies to silicic ignimbrites and tuffs. Sedimentary units, generally occurring as lenses of limited extent and thickness, occur in many parts of the volcanic sequence between flows (Geukens, 1960, 1966). These are generally composed of lacustrine deposits consisting of calcareous sandstone, mudstone and reworked volcanic clasts. Also observed in inter-trap sedimentary units are fluvio-aeolian sands and palaeo-soils, generally lateritic, often developing along plane surfaces but at times locally cutting across different beds. The Yemen Volcanic Group is intruded by granitoid rocks along much of the edge of the High Plateau of Yemen, which forms the great eastern escarpment of the Red Sea. Intrusions also occur in the Sana’a and Taiz districts. The Yemen Volcanic Group includes all the

Cenozoic volcanic rocks, which is divided into the Yemen Trap Series (31.6 - 15 Ma) that consists of thick series of mainly flood volcanic rocks and Yemen Volcanic Series (10 - 0 Ma) that represents thinner series of mainly peralkaline intraplate basaltic volcanic rocks (Mattash and Balog, 1994). The Yemen Volcanic Series is divided into older volcanic rocks intruded west of Aden (10 - 5 Ma) and younger volcanic rocks east of Aden (5 - 0 Ma).

1.9. Reservoir Characteristics:

The main reservoirs in the Block-14 are Qishn Clastic, Saar Clastic, Saar Carbonate, Basil Sand, Madbi Carbonate, and Basement Formation. The Masila fields are associated with the Upper Jurassic to Lower Cretaceous Sayun-Masila rift graben basin. Almost 90% of the oil reserves are discovered in the Lower Cretaceous Upper Qishn.

Sandstones, Qishn Formation, Tawilah Group. Oil also is found in seven other reservoirs consisting of Lower Cretaceous and Middle to Upper Jurassic Clastics and Carbonates as well as Fractured Granitic Basement. In Masila Block-14, the 198 m (650 ft.) thick Qishn Clastics Member is further subdivided. The 128 m (419 ft.) thick Lower Qishn Clastics. The 70 m (231 ft.) thick Upper Qishn Clastics. This talk focuses on the main oil producing reservoirs, which are the informally named Upper Qishn Sandstones of the formal Qishn Clastics Member, Qishn Formation, Tawilah Group.

1.10. Stratigraphy of Al-Masilah

Upper Qishn:

The Upper Qishn Sandstone layers of the Qishn Formation are stratigraphically subdivided into three informal units which are: upper S1, middle S2, and bottom S3. When it comes to S1, it is referred to the first sandstone layer encountered below the Qishn Carbonates Member; followed by the S2 and S3. Additionally, The S1unit is subdivided into three smaller units (S1A, S1B, and S1C) based on whether there is non-reservoir (carbonate and shale) lithologies or not.

Overall, the upper Qishn sandstones are excellent in terms of quality, and they are with no inhibiting authigenic clays or diagenetic problems due to their quartz-rich composition and relatively shallow depth of burial. The primary porosities ranging between 15% and 28%, with a porosity that reach about 20%. On the other hand, the permeabilities are excellent and their range could be up to 10 Darcies with a permeability of almost 1.5 Darcies. The upper Qishn sandstones are relatively homogeneous and uninterrupted in the lower half of the formation and are more the opposite in the middle to upper sections.

Lower Qishn:

The Lower Qishn Formation is divided into two intervals (upper LQ1 and lower LQ2). The LQ1 sandstones were deposited in an arid alluvial fan/plain to fluvial setting and are generally less mature than the overlying Upper Qishn sandstones. Moreover, The LQ2 sandstones were deposited in a transgressive tidal flat to subtidal estuary bay environments. The LQ2 have quartz-rich sandstones that are texturally mature and their grains are fine to medium. The LQ2 also has several sandstone reservoir quality intervals with proven trapped hydrocarbons across the Al-Masila Block.

Furthermore, the LQ2 is Informally divided into three main reservoir layers (LQ2-10, LQ2-20, and LQ2-30). The quartz rich LQ2 tidal channel / shoal reservoir has a good to excellent reservoir quality. In the reservoir quality, the porosity values are up to 28% while the permeability values are more than 1000 mD; the average porosity and permeability values are 25% and 560 mD.

Upper Saar:

The Upper Saar Formation consists of a mingled Carbonate and a Clastic succession which is unconformable over and underlain by the Lower Qishn and Saar Formations, respectively. The Upper Saar is further subdivided into four informal Clastic and carbonate sequences annotated by using an A through D suffixes. Likewise, all of the four Upper Saar units have reservoir potential across the Masila Block.

When it comes to quality, the Upper Saar-A sandstone has average porosity values that range from 14% to 22% and it could have porosity values as high as 25%. Additionally, the average permeability is very good in the Upper Saar-A sand, varying from 5 mD to 1072 mD with permeability as high as 2030 mD in some areas.

Overall, the Upper Saar B and D dolostones are of fair to excellent quality with secondary vuggy porosity enhanced by diagenetic subvertical to vertical microfractures. The Average porosity values in the Upper Saar-B are vary from 5% to 11% with porosity as high as 18%. In the Upper Saar-D, average porosity is in the 6% to 11% range with porosity as high as 17%. In the Upper Saar-B average permeability varies from 18 mD to 485 mD with permeability values as high as 1810 mD. In the Upper Saar-D, average permeability varies from 2 mD to 73 mD with permeability values up to 165 mD.

On the whole, the Upper Saar C reservoir quality is fair to very good with well-connected primary intergranular porosity and secondary porosity generated by dissolution of feldspars. Also, some microporosity is preserved in authigenic clay, detrital clays, and partially leached feldspar grains. Lastly, the average porosity in the Upper Saar-C is typified by porosity in the 15% to 19% range with porosity values up to 24%.

Saar Carbonate:

Saar Carbonate Reservoir, primary intercrystalline, intergranular, and secondary leached vuggy porosity types are present in the core samples obtained up to date. The permeabilities may also be inconstant depending on the primary fabric and degree of diagenetic alteration. There is also a high energy oolitic shoal facies is present at the top of the Saar Formation in the Tawila pool. Moreover, the shoal facies remained free of secondary destructive processes and therefore retained excellent reservoir quality porosity and permeability.

On the other hand, a significant secondary porosity development may be the defining reservoir characteristic in many lower energy lagoonal facies. For instance, a low energy wackestone facies in the Tawila area is not a suitable reservoir rock because of its poor primary porosity and permeability. The reservoir is then developed by an early secondary leaching process creating a vuggy reservoir with excellent porosity ranging from 12 to 23% and permeability of a value greater than 125 mD. Furthermore, dolomitization may also be a secondary key process that creates a reservoir with quality rock while extensive dolomitization along paleo highs may locally improve some limestone reservoirs. For example, thin dolomite reservoirs within the Tawila structural high have greater than 20% porosity and up to 1000 mD permeability.

Lower Saar:

Concerning the lower Saar Reservoir, only one field on the Masila Block has been assigned Proved reserves from the Lower Saar reservoir which is the Ressib Field. The field (the Ressib Field) has proven to be productive from a shallow marine platform facies dominated by Rudists. Reservoir quality development was a function of Rudist dissolution, which resulted in an abundance of moldic porosity. To add, the gross reservoir thickness of the Ressib-2 is approximately about 176 feet, with net reservoir measuring of 66 feet in terms of thickness. Finally, the reservoir has an average porosity of 10% and a PI of 2.5.

Additionally, partial dolomitization of the Lower Saar has been observed in the Ressib Field, although reservoir quality is not necessarily dependent on dolomitization. Also, reservoir quality rock has been observed in both dolostone and limestone lithofacies.

Madbi:

Only one field on the Masila Block has been assigned Proved reserves from the Madbi Limestone reservoir and that is the Northeast Camaal Field. This field has proven to be productive, and it has been producing from the upper member of the Madbi Limestone. The reservoir interval is toward the top of the member where porous platform margin debris has prograded out over tight slope facies. The reservoir is variable in thickness (12-48 feet thick) and has an average porosity of 11-13%. To conclude, the reservoir is interpreted to consist of allochthonous carbonate material, primarily olitic and skeletal grainstone, shed from an adjacent margin.

Madbi Fan:

It is a skeletal grainstones, packstones, and wackestones form the early syn-rift Madbi Fan reservoir on the south flank of the Sunah Field. This reservoir is composed of coarse shell debris (shallow water origin) and fragments of granite that were shed from the high side of a basement fault to form a deep water fan flanking the fault scarp. This reservoir is directly in contact with the fractured Basement reservoir through the fault face and it also communicates with it. The Madbi Fan reservoir average porosity is 17% porosity with permeabilities from 100 to more than 1,000 mD. In short, the thickest and best reservoir is concentrated in the proximal fan with thickness and quality decreasing toward the distal edges. The Madbi Fan is also an oil productive reservoir in the Sunah Field.

Basal Sand:

Basal Sandstone Reservoir is a subarkosic sandstone derived from erosion of pre-rift Basement, and it inherited the composition of the Basement. The productive basal sandstone is dominated by the more stable quartz grains with some remnant feldspars and igneous rock fragments bound by calcite cement. It grades from coarse beach sands with excellent reservoir quality to fine grained offshore argillaceous limestones with no reservoir potential. Moreover, heavy minerals such as pyrite and barite are concentrated in low pockets and have a remarkable effect on the petrophysical log response. The productive Basal Sandstone has an average well porosity of 11-14% with permeabilities of 100 to 3,000 mD. In a nutshell, The Basal Sandstone is ab oil productive reservoir in both the Sunah and North Camaal Fields, and is hydrocarbon charged, but tight, in the Northeast Camaal Field.

Basement:

The Basement Reservoir, fractured rocks (immediately below the Basal Sandstone /Madbi Limestone section) have locally been proven to be important reservoirs in the Masila Block. Oil is currently being produced from the Basement in the Sunah, North Camaal, and Northeast Camaal fields. On the other hand, it is difficult to directly measure porosity within fractured Basement.

Additionally, Core recoveries are generally very poor and open-hole logs are often difficult to accurately interpret. Regarding the basement quality, its average porosity is in the range of 1.5% is assumed for typical fracture zones, though effective porosity and permeability are highly variable as fracture intensity that is not evenly distributed. Matrix porosity of 5 to 10% or greater and it has been calculated in some of the Basement section within specific lithology types, but within the Sunah Basement it is complex (not widely seen). Also, the local permeability can be extraordinarily high, though typical Basement permeability is very low.

1.11. Reservoir Stimulation Methods:

Reservoir stimulation is an approach performed to repair damage or improve reservoir productivity. There are many ways to stimulate the productivity/injectivity of a well and the most widely used techniques are:

1.11.1. Chemical Methods

a) Matrix Acidizing:

Matrix acidizing is one of two chemical stimulation processes in which acid is injected into the well penetrating the rock pores at pressures below fracture pressure to either stimulate a well to improve flow or to remove damage. As matrix acidizing is performed, the acids dissolve the sediments and mud solids within the pores that inhibits the permeability of the rock. This process expands the natural pores of the reservoir which stimulates the flow of hydrocarbons. Matrix acidizing operations are ideally performed at high rate, but at treatment pressures below the fracture pressure of the formation. This enables the acid to penetrate the formation and extend the depth of treatment while avoiding damage to the reservoir formation.

Moreover, most sandstone formations are composed of quartz particles (SiO2) which are bonded together by various types of cementing materials like carbonates, silica and clays. The adversity of the materials in a formation makes it difficult to predict the outcome of any reaction. As a result, the hydrochloric acid will not be sufficient enough to dissolve the rock.

The perfect primary reaction of the hydrofluoric acid on sand (Silicon Dioxide) and clay looks as follows:

- Silicon Dioxide:

$SiO_2 + 6HF \longrightarrow H_2SiF_6 + 2H_2O$

- Clays:

$Al_2SiO_{10}(OH)_2 + 36HF \rightarrow 4H_2SiF_6 + 12H_2O + 2H_3AlF_6$

Furthermore, both hydrochloric and hydrofluoric acids should be used together due the composition of sandstone rocks.

On the other hand, carbonate formations are mainly composed of limestone $CaCO_3$ and dolomite $CaMg(CO_3)_2$, and they rapidly dissolve in hydrochloric acid to then create new products like calcium chloride($CaCl_2$), magnesium chloride ($MgCl_2$), carbon dioxide (CO_2) and water as follows:

- Limestone:

$CaCO_3 + 2HCL \longrightarrow CaCl_2 + CO_2 + H_2O$

- Dolomite:

$CaMg(CO_3)_2 + 4HCL \longrightarrow CaCl_2 + MgCl_2 + CO_2 + H_2O$

The reaction rate of the limestone and dolomite with the hydrochloric acid can cause wormholes up to 10 feet long near the wellbore area connected to the flow channels. Additionally, dolomite reacts more slowly with the hydrochloric acid than limestone.

b) Closed Fracture Acidizing Treatments (CFA):

Closed Fracture acidizing treatments are techniques used to inject acid into an already hydraulically fractured carbonate formation at a pressure below the pressure necessary to reopen the fracture. In this pressure below the pressure necessary to reopen the fracture. The most commonly used fluid in acid fracturing is 15% hydrochloric acid (HCl). To obtain more acid penetration and more etching, 28% HCl is sometimes used as the primary acid fluid. In this type of treatment, the acid flows into existing openings between the fracture faces and creates " wormholes, " which generate flow channels through which formation fluid may flow into the wellbore. The acid actually dissolves more rock than regular matrix acidizing or open-fracture treatments. The basic concept of CFA is to inject acid into a closed fracture. As acid flows down the fracture, it may be in turbulent condition, thus dissolving more formation in a given time period than acid flowing down an open fracture. Moreover, the acid should be injected at a pressure high enough to allow preferential flow into existing grooves of the already hydraulically fractured formation. Injection pressure, however, should not be high enough to open or propagate the fracture. This upper limit is usually referred to as the opening pressure.

1.11.2. Mechanical Methods:

a) Hydraulic Fracturing:

Hydraulic fracturing, informally referred to as “fracking,” is an oil and gas well development process that typically involves injecting water, sand, and chemicals under high pressure into a bedrock formation via the well. This process is intended to create new fractures in the rock as well as increase the size, extent, and connectivity of existing fractures. Hydraulic fracturing is used commonly in low-permeability rocks like tight sandstone, shale, and some coal beds to increase oil and/or gas flow to a well from petroleum-bearing rock formations. As the process is applied, the pressure in the wellbore increases to a value called the break-down pressure, that is the sum of the in-situ compressive stress and the strength of the formation. Once the formation “breaks down,” a fracture is formed, and the injected fluid flows through it. From a limited group of active perforations, ideally in a normal fault stress regime, a single vertical fracture is created that propagates with two "wings" being 180° apart and identical in shape and size. Furthermore, Fluid not containing any solid (called the “pad”) is injected first, until the fracture is opened wide enough to accept a propping agent. The purpose of the propping agent is to keep apart the fracture surfaces once the pumping operation ceases and the pressure in the fracture decreases below the compressive in-situ stress trying to close the fracture. In deep reservoirs, man-made ceramic beads are used to hold open or "prop" the fracture. In shallow reservoirs, sand is normally used as the propping agent.

Hydraulic fracturing can do the following:

- Increase the flow rate of oil and/or gas from low-permeability reservoirs.
- Increase the flow rate of oil and/or gas from wells that have been damaged.
- Connect the natural fractures and/or cleats in a formation to the wellbore.
- Decrease the pressure drop around the well to minimize sand production.
- Enhance gravel-packing sand placement.
- Decrease the pressure drop around the well to minimize problems with asphaltine and/or paraffin deposition.
- Increase the area of drainage or the amount of formation in contact with the wellbore.
- Connect the full vertical extent of a reservoir to a slanted or horizontal well.

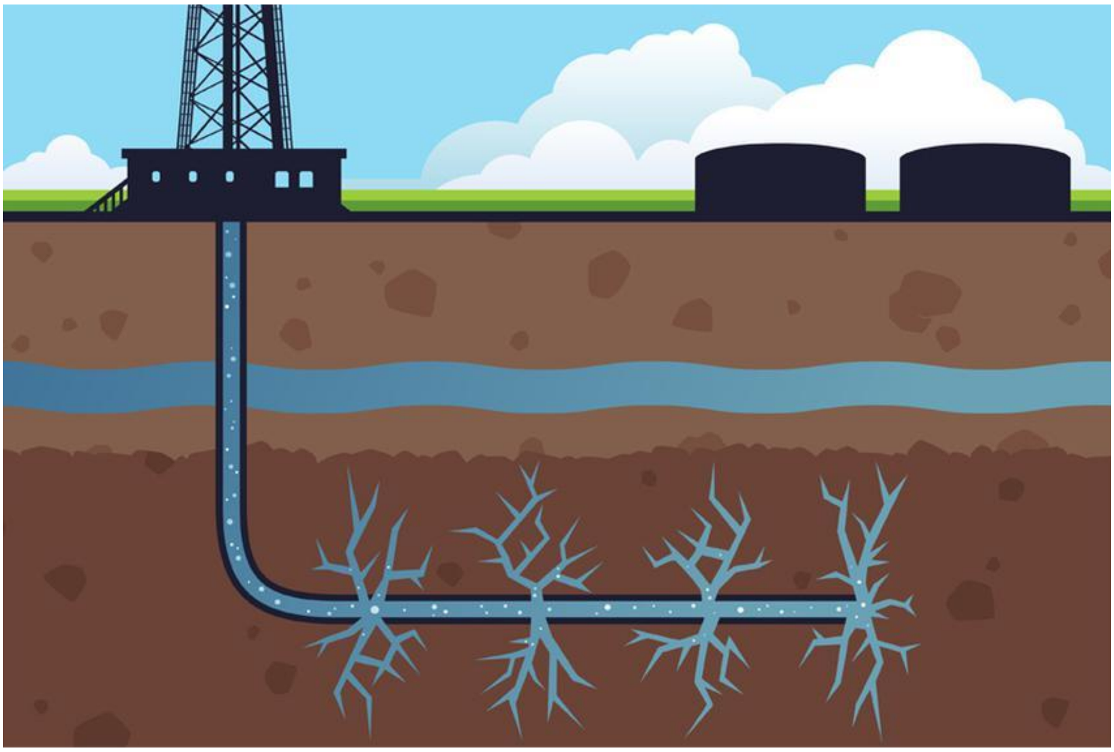


Figure 1-4 Hydraulic Fracturing

b) Explosive Fracturing:

It is defined as the application of explosives in tight petroleum formations to improve permeability by extending the existing fracture system and creating a secondary system of fractures. A liquid explosive is displaced into an induced fracture and detonated. The energy of the detonation is liberated deep within the formation. This method differs from conventional well-bore shooting, which affects only the well bore and adjacent formation rock near the charge. Fracturing fluid for in fracture explosion has two functions which are to carry solid explosives while create hydraulic fractures, and to propagate ignition. Moreover, Explosive fracturing of the petroleum formation adjacent to the well is carried out in the presence of a propping agent, such as glass beads, sand or aluminum particles. The propping agent explosive combination is preferably surrounded by granular ammonium nitrate explosive to insure the absence of voids in the well bore.

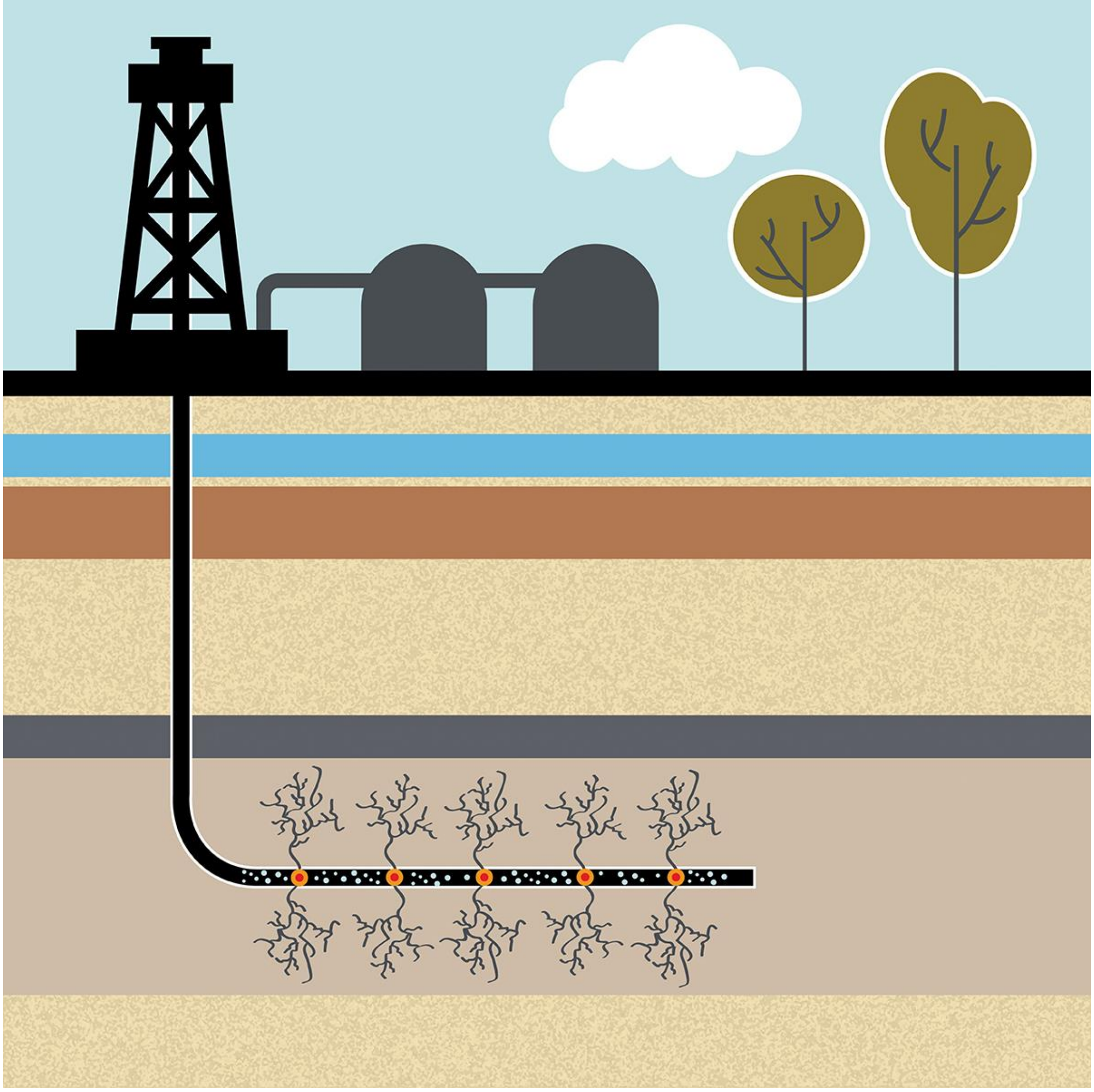


Figure 1-5 Explosive Fracturing

c) Kiel Fracturing:

The third mechanical technique is called the Kiel Process that uses a cyclic injection procedure to form extraordinarily long, branching flow procedure to form extraordinarily long, branching flow channels in naturally fractured formations. The cyclic treatment induces spalling from the fracture faces. The spalls plus some injected fracturing sand help form branching fractures propped by a partial monolayer of spalls and containing flow channels with very high conductivity.

Conventional fracturing fluids and equipment are employed. The method has been applied with good results to a wide range of formations at depths to 11,500 ft.

1.11.3. Combined Methods:

It is a combination of both mechanical and chemical methods and it is divided into two types:

a) Acid Fracturing:

Acid fracturing is a production stimulation technique that has been widely used by the oil industry. In such a treatment, acid or a fluid used in a pad ahead of the acid, is injected down the well casing or tubing at rates greater than the rate at which the fluid can flow into the reservoir matrix. This injection produces a buildup in wellbore pressure sufficient to overcome compressive earth stresses and the formation's tensile strength. Failure then occurs, forming a crack (fracture). Continued fluid injection increases the fracture's length and width. Acid injected into the fracture reacts with the formation to create a flow channel that remains open when the well is put back on production. To achieve reservoir stimulation, an acid fracturing treatment must produce a conductive flow channel long enough to alter the flow pattern in the reservoir from a radial pattern to one that approaches linear flow.

b) Fishbone Lateral Stimulation:

It is an advanced type of stimulation method that is an equipment which looks like the fish bones used in carbonates, coal bed methane, and oil sands. It was concluded that fishbone stimulation could increase well productivity, reduce skin factor, and reduce potential water or gas coning. It utilizes flexible grid size and shape and claims to calculate fluid flow equation accurately and effectively. Fishbone is used when there is formation damage, low vertical permeability, and heterogeneity. It also helps to increase effective wellbore radius, prevent stimulation into unwanted zones, and distribute stimulation and production and to distribute stimulation and injection.

Figure 1-6 Fishbone Lateral Stimulation

1.12. The Importance of Acid Stimulation:

- Reduce formation damage.
- Enhance the productivity.
- Improve the porosity and the permeability of the formation.
- Extend the production life of the well.

CHAPTER TWO

2. LITERARUE REVIEW

2.1. Introduction

2.1.1. General Overview:

The main objective of a stimulation treatment is to increase the rate at which the formation delivers hydrocarbons naturally. Acid treatments have been applied to wells in oil and gas bearing rock formations for many years. Acidizing is a widely used work-over and stimulation practice in the oil industry. By dissolving acid soluble components within underground rock formations or removing material at the wellbore face, the flow rate of oil or gas out of production wells or the flow rate of oil-displacing fluids into injection wells may be increased. Acidizing predates just about all well stimulation techniques. Other techniques, such as hydraulic fracturing, were developed recently. Acidizing may, in fact, be the oldest stimulation technique in modern use. The earliest acid treatments of oil wells are believed to have occurred as far back as 1895. The Standard Oil Company used concentrated hydrochloric acid (HCl) to stimulate oil wells producing from carbonate formations in Lima, Ohio, at their Solar Refinery. The acidizing process was applied with great success in the Lima, Ohio wells. Many wells were acidized with remarkable results in the short term. However, the first acid treatment in 1895 was probably considered a novel idea that would not last very long, and acidizing was used very infrequently during the next 30 years probably due to the lack of an effective method for limiting acid corrosion. However, throughout its history, acidizing has a repeating record of quickly and inexplicably losing popularity, seemingly independent of results at times. Because of the growing interest surrounding acid treatments of limestone formations, new treatments for sandstone formations began to appear. In 1933, Halliburton conducted the first sandstone acidizing treatment using a mixture of hydrochloric and hydrofluoric acid (HF), in a test well belonging to the King Royalty Co., near Archer City, Texas. Unfortunately, the results of the first attempt were very discouraging. Dowell did introduce a mixture of 12% HCl – 3% HF, called “Mud acid”, in 1939. Successful wellbore treatments were pumped in the Gulf Coast area. This acid mixture is still quite common and is now known as “regular strength” mud acid. In 1947, the first hydraulic fracturing treatment was completed in the Hugoton Field (Kansas) and fracking has also become a standard treatment to improve production. Since that time, hydraulic fracturing has increased recoverable reserves more than any other technique. Historically, carbonate fracture acidizing has experienced limited success in geologic reservoirs characterized by high-closure stress or temperatures above 120° C. Although many formations in North America are sandstone and require the use of granular propping agents, acid fracturing is more commonly used in Europe and the Middle East, especially in Bahrain and Saudi Arabia. Numerous matrix acidizing treatments of sandstone formations have been conducted since the mid1960s. In the 1970s and early 1980s there was a proliferation of “novel” sandstone acidizing systems, in order to provide certain benefits such as retarding HF spending, stabilizing fine particles, preventing precipitation of HF-rock reaction products. In the 1980s and into the 1990s, developments in sandstone acidizing addressed treatment execution more than fluid chemistry. More recently, fluid chemistry has again stepped to the forefront (twists on old systems are developed). Recent years have seen a marked increase in well stimulation activity (acid and frac jobs) with the number of treatments performed more than doubling through the 1990s. In 1994, 79% of the jobs were acid jobs, but since they are lower cost than hydraulic fracturing treatments, they only consumed 20% of the money spent for well stimulation. For acid jobs, the observed failure rate was 32%. Failure rate for the less frequent but more expensive hydraulic fracturing treatments was much lower, only 5%. In analyzing the reasons for job failure, one-third were due to incorrect field procedures, while two-thirds were attributed to incorrect design or improperly identifying well damage. The acidification of geothermal wells is not frequently used but the operations were borrowed from the treatments performed on oil or gas wells.

2.1.2. Technology overview

Advances in oil and gas well stimulation—matrix acidizing, fracture acidizing, hydraulic fracturing, extreme overbalance operations—enable operators to optimally increase well/reservoir productive capacity. Two basic types of acidizing operations can be conducted: (1) Matrix acidizing is performed below fracturing rate and pressure. Acid flows through the matrix with reactions taking place in existing pores and natural fractures. (2) Fracture acidizing is performed above fracturing rates and pressures. Etching of the created fractures provides well stimulation, not just damage removal. Acid fracturing treatments can be a solution for wells with impaired production. Not only would acid fracturing increase well productivity, but it also would help retain the generated hydraulic conductivity for a longer time period. The design of any acid-stimulation treatment should begin with a thorough evaluation of the characteristics of the targeted formation. The composition, structure, permeability, porosity, and strength of the rock must be determined, along with formation temperature and pressure and the properties of reservoir fluids. Furthermore, understanding reservoir mineralogy is essential to designing truly effective acidizing treatments. For most of the 20th century, acidizing oil and gas wells to optimize production gave unacceptably erratic results in primary and remedial applications. The reliability and effectiveness of acid-stimulation technology began to change for the better in the mid-1990s, driven by improved understanding of the complex chemical and physical reactions of minerals with acidizing fluids. Both fundamental and applied research, and results of field work all have confirmed that—whether in a sandstone or carbonate reservoir, a mature field, deep water environment, or high-temperature reservoir—reliably achieving long-term production increases from acidizing requires a thorough understanding of the formation mineralogy. Essentially, the productivity of a given well may be impaired either by the natural characteristics of the reservoir rock and fluids or by damage resulting from drilling, completion or production operations. Fracture acidizing treatments can be designed that penetrate deep into lower permeability rock.

2.1.3. Matrix acidizing

This process is performed below fracturing flow rate and pressure and it is normally used for the removal of skin (near-wellbore) damage associated with work-over, well killing or injection fluids to increase formation permeability in undamaged wells. With respect to acidizing, especially sandstone acidizing, assessment of formation damage is perhaps the single and most important factor in treatment design. To assess formation damage, it is necessary to know the skin term in the Darcy’s law equation defining well production rate, and its effect on production rate. The production rate is directly proportional to permeability and inversely proportional to skin. Skin damage is a mathematical representation of the degree of damage present. Permeability and skin can be measured with a pressure transient well test. Formation damage can occur during any well operation, including: drilling; cementing; perforating; production; workover; stimulation. Therefore, in assessing formation damage, all aspects of a well and its history should be investigated, including: reservoir geology and mineralogy; reservoir fluids; offset well production; production history; drilling history (including fluids used); cementing program (including cement bond logs); completion and perforation reports (including fluids used); workover history; stimulation history.

In order to make the most of acidizing, acid treatment design must be approached as a process. The general approach is as follows:

1- Select an appropriate stimulation candidate well.
2- Design an effective treatment.
3- Monitor the treatment for subsequent improvement.

Treatment volumes for matrix acidizing range from 120 to 6,000 liters per meter (L/m) of targeted interval, pumped at the highest rate possible without fracturing the formation.

- **Wormhole Formation**

Wormholes form when the invasion flow of the reactive fluid through the porous media is nonuniform. The below figure shows the "Skelton" of a wormhole which is an epoxy casting of the dissolved pore space or wormhole formed in a carbonate core as a result of matrix acidizing. Moreover, wormholing is the preferred dissolution process for matrix acidizing in carbonate formations because its efficiency forms highly conductive channels. Large permeability incensement can be achieved with fractional pore volumes of acid, so the live acid penetration can be significantly greater than the average radial fill around a wellbore, resulting in a greater reduction in skin factor for an equivalent volume of acid pumped. It should be noted that the acid injection rate has an impact on the wormholes efficiency. For instance, when the rate of acid injection is low , no wormholes or skin reduction occur while the opposite happens if the injection rate is high enough.

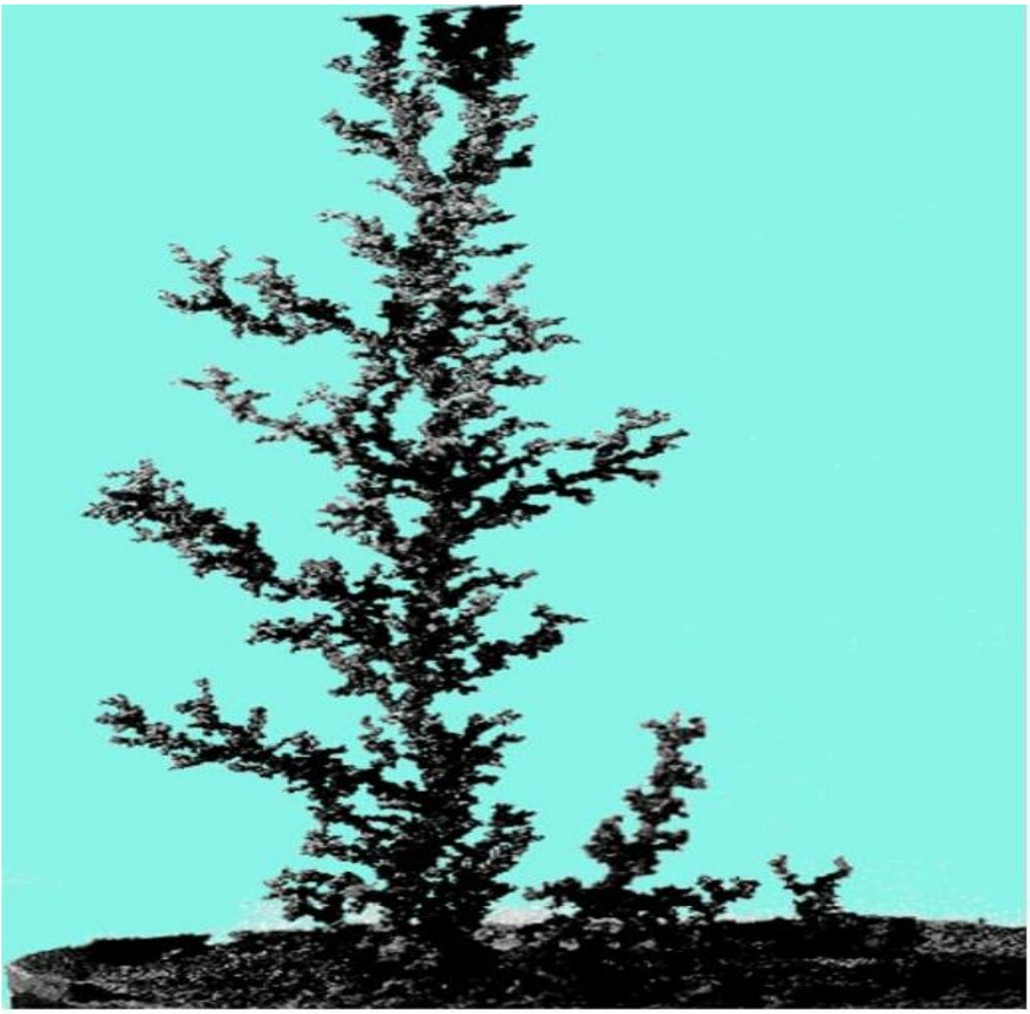
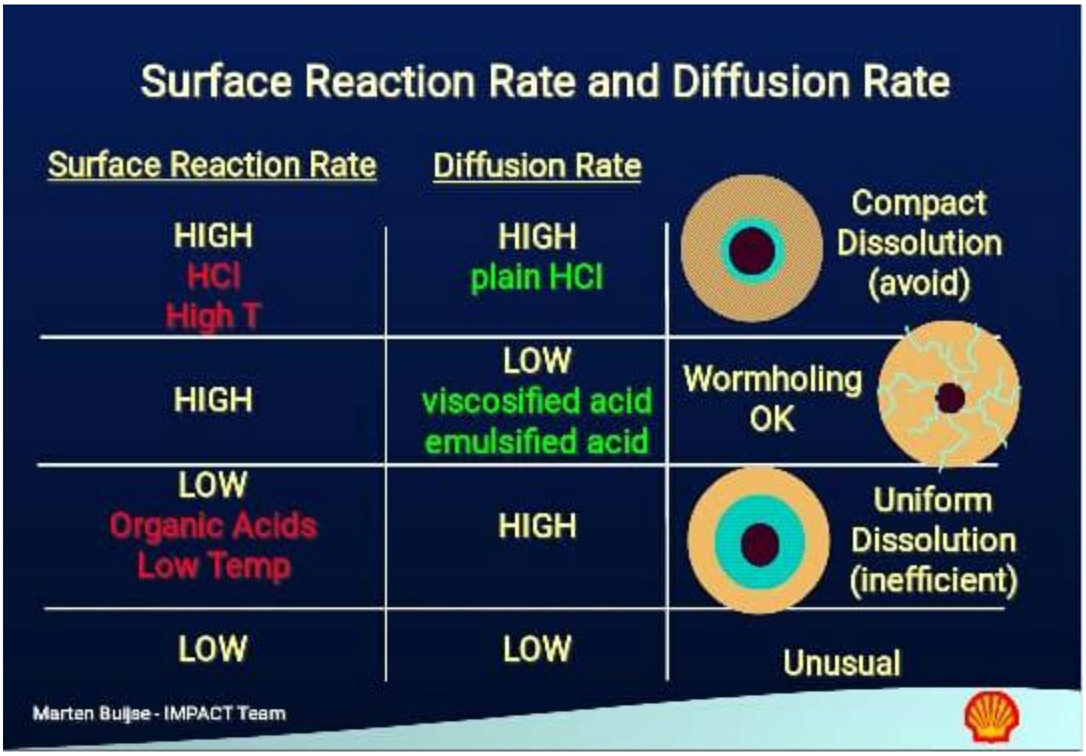


Figure 2-1 Wormholes Illustration

- **Acid Diffusion Rate**

Acid diffusion rate indicates how fast the transportation of acid from the bulk of the fluid to the rock surface is. The diffusion rate is a function of the acid system. Moreover, both of these parameters are also a function of temperature. Either the surface rate or the diffusion rate may control the overall acid spending rate, though both are always in balance with each other. Wormholes form when the overall acid spending rate is diffusion-limited, which result from a high surface reaction rate or low diffusion rate.

Under condition that do not inherently favor wormhole formation, increasing the acid injection rate can allow wormholes to initiate and grow. More correctly, increasing the fluid velocity allows live acid to be transported deeper into the formation. In laboratory core flow tests, an optimum injection rate can be determined. This rate will vary according to the sample configuration, test temperature, properties of the rock and acid system injected. For any given set of conditions, a critical velocity exists. Injection rates below this velocity will result in wormholes. For example, at 175° F, with a 99.5% pure limestone under linear flow conditions, the critical velocity of wormhole formation is 1.43 cm/s for plain 15% HCl and 0.29 cm/s for emulsified 15% HCl. The absolute magnitude of the critical velocity is not as significant as the face that emulsified acid is five times less reactive than plain acid. Therefore, the choice of fluid system can optimize matrix acidizing treatments. Retarded acid systems can offset pump rate limitations imposed by low permeability, high pressures, or equipment constrains.



Surface Reaction Rate and Diffusion Rate

Surface Reaction Rate	Diffusion Rate	
HIGH HCl High T	HIGH plain HCl	Compact Dissolution (avoid)
HIGH	LOW viscosified acid emulsified acid	Wormholing OK
LOW Organic Acids Low Temp	HIGH	Uniform Dissolution (inefficient)
LOW	LOW	Unusual

Marten Buijse - IMPACT Team

Figure 2-2 Acid Diffusion Rate Impact on Formation

2.1.4. Fracture acidizing

Fracturing treatments are defined as the treatments in which the injection rate of the fluid is larger than the fluid leak off into the matrix of the formation. Pressure in the wellbore will therefore buildup and eventually lead to tensile failure of the rock, creating a conductive channel. Because of the reactive nature of the fluid, the addition of acid in treatments can dissolve and remove primary and secondary minerals (scales) sealing the fractures. The aim is to change the future flow pattern of the reservoir from radial to linear to effectively stimulate the reservoir and increase production.

Fracture acidizing, the ideal but rarely achieved outcome is a fracture plane that is continuously conductive from the wellbore all the way to the tip to provide maximum production enhancement from the surrounding rock. To be effective, etched fracture surfaces must retain sufficient conductivity for production enhancement after fracture closure. Although a large mass of rock may be dissolved, if the resultant fracture face dissolution does not render the surfaces with sufficient differential relief, the fracture conductivity under closure stress will be low at least for sedimentary rocks. If the acid spends too quickly, excessive spending and acid leak off near the wellbore will result in little or no conductivity toward the fracture tip. Lack of active acid penetration depth along the fracture plane will result in very short conductive fractures. Sometimes, acid fracturing was preferred to hydraulic fracturing because proppant cleanout in a well with coiled tubing required operational and safety resources. Additionally, the high conductivity of an acid etched fracture made acid fracturing a more attractive technique if comparable fracture lengths could be achieved. After several acid fracturing treatments were experienced, it became clear that a normal response of the treated wells was a sharp production increase followed by a slight gain in average production. Also called acid fracking, this technique is widely used for stimulating limestone, dolomite formations or formations presenting above 85 % acid solubility. It consists to inject first a viscous fluid at a rate higher than the reservoir matrix could accept leading to the cracking of the rock. Continued fluid injection increases the fracture's length and width and injected HCl acid reacts all along the fracture to create a flow channel that extends deep into the formation. The key to success is the penetration of reactive acid along the fracture. However, the treatment volumes for fracture acidizing are much larger than the matrix acidizing treatment, being as high as 12 000 - 25 000 L/m of open hole. Three geometric quantities are needed for proper treatment design: - Acid penetration: distance travelled by acid at end of pumping. - Live acid penetration: farthest point reached by live acid at end of given pumping stage (live HCl strength > 0.10%). - Etching distance: maximum distance that etching has occurred. For a one acid stage treatment this is the same as live acid penetration.

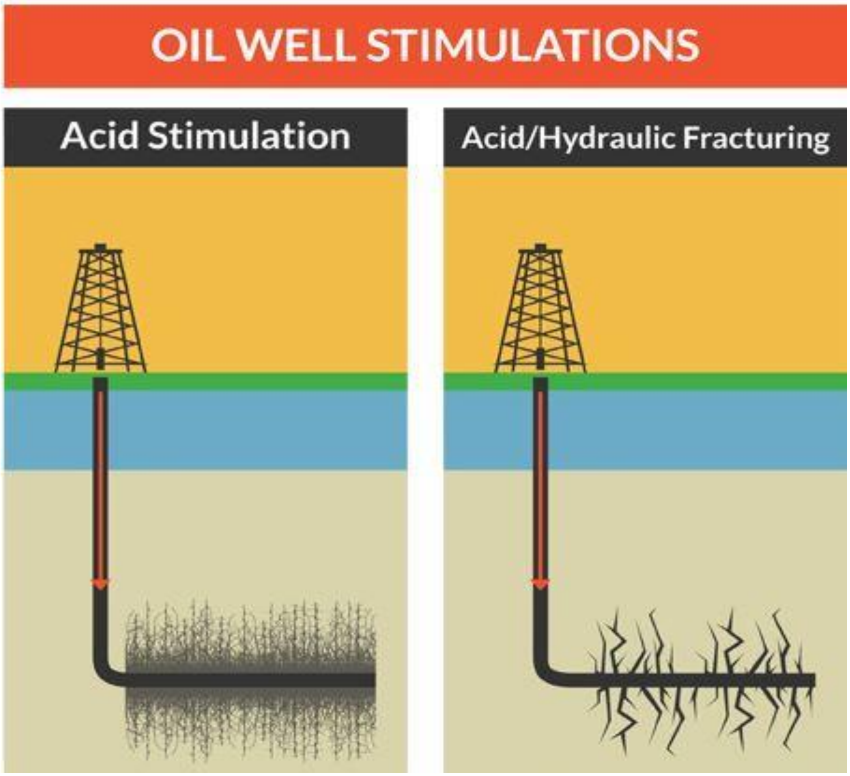


Figure 2-3 Matrix Acidizing and Hydraulic Fracturing Illustration

2.1.5. Conventional acid systems

A number of different acids are used in conventional acidizing treatments. The most common are: - Hydrochloric, HCl - Hydrofluoric, HF - Acetic, CH3COOH - Formic, HCOOH - Sulfamic, H2NSO3H - Chloroacetic, ClCH2COOH. These acids differ in their characteristics. Choice of the acid and any additives for a given situation depends on the underground reservoir characteristics and the specific intention of the treatment, for example near well bore damage removal, dissolution of scale in fractures, etc. Factors controlling the reaction rate of acid are: area of contact per unit volume of acid; formation temperature; pressure; acid concentration; acid type; physical and chemical properties of formation rock and flow velocity of acid. These factors are strongly interrelated. Reaction time of a given acid is indirectly proportional to the surface area of carbonates in contact with a given volume of acid. Extremely high area-volume ratios are the general rule in matrix acidizing. Therefore, it is very difficult to obtain a significant acid penetration before spending during matrix treatments. As temperature increases, acid spends faster on carbonates. It is often necessary to increase pumping rate during acid fracturing to place acid effectively before it is spent. Pre-cooling the formation, or alternating stages of acid and water is another approach. An increase in pressure up to 500 psi will increase spending time for HCl. Above this pressure, only a very small increase in spending time can be expected with increases in pressure. As concentration of HCl increases, acid spending time increases because the higher strength acid dissolves a greater volume of carbonate rocks. This reaction releases greater volumes of CaCl2 and CO2, which further retards HCl. Physical and chemical composition of the formation rock is a major factor in determining spending time. Generally, the reaction rate of limestone is more than twice that of dolomite; however, at high temperatures reaction rates tend to be nearly equal. Velocity has a large effect on reaction rate. Retarded acids should be evaluated under flowing conditions since static tests often yield misleading results. In fracture acidizing, an increase in pumping rate increases fracture width. This decreases area-volume ratio, thereby increasing acid reaction time. The majority of acidizing treatments carried out utilize hydrochloric acid (HCl). However, the very fast reaction rate of hydrochloric acid, and other acids listed above, can limit their effectiveness in a number of applications. All conventional acids including HCl and organic acids react very rapidly on contact with acid sensitive material in the wellbore or formation. Wormholing is a common phenomenon. The rapid reaction means the acid does not penetrate very far into the formation before it is spent. Conventional acid systems are therefore of limited effectiveness in treatments where deep acid penetration is needed. There was an early recognition that it was desirable to delay the rate of reaction of the acid and a variety of techniques have been developed to achieve this. Patents relating to several of these techniques have been issued. Further information on these retarded acid systems is given below.

2.2. Acid Candidates

A good matrix acidizing candidate is achieved in any well producing from:
- Formation with permeability greater than 10 mD.
- Permeability of which in the near-wellbore or near-perforation region has been reduced by solid plugging.

This plugging can be either mechanical or chemical. Mechanical plugging is caused by either introduction of suspended solids in a completion or workover fluid, or dispersion of in-situ fines by incompatible fluids and/or high interstitial velocities. Chemical plugging is caused by mixing incompatible fluids that precipitate solids. Additionally, there are more than one type of acids, with different concentrations, to use in the acidizing treatment depending on several factors like the type of formation we deal with and other key factors and here are the types of acids that we can use:

2.2.1. Inorganic Acids

a) Hydrochloric Acid (HCL)

It's considered to be the best field acid for most applications; however, it has no limitations. Hydrochloric acid is also quite reactive; therefore, the time of usage will be quite rapid on some formations. Additionally, there must be some additives to be added depending on the reactions rate and time. These additives also must survive the process and function in the spent acid. Furthermore, certain materials are soluble in hydrochloric acid but not necessarily in the spent acid water. For instance, calcium sulphate can be partially solubilized by hydrochloric acid, yet it will crystallize out as scale when the acid spends. Likewise, Iron oxide will dissolve in hydrochloric acid by will re-precipitate, as the main acid spends, at about a PH of 2.0. These properties require the selection of additives that will circumvent these problems.

Hydrochloric acid is normally pumped in concentrations ranging from 2 to 28%. Lower concentrations acids are used for the removal of salt plugs and emulsions while the higher acids are selected to achieve a longer reaction times and to create a larger flow channels in the treatment zone.

The most frequent used strength is 15%for the following reasons:

- Less cost per volume than stronger acids.
- Less costly to inhibit.
- Less dangerous to handle.
- They will retain larger quantities of dissolved salts in solution after spending.

Hydrochloric acid has many advantages some of which are:

- Low cost and availability.
- Easily inhibited to prevent attack on oil-field tubulars.
- Surface tension can be controlled to aid in:
  i. Penetration.
  ii. Wetting properties.
  iii. Exhibit detergency.
  iv. Reducing friction pressure.
- Can be emulsified for slower reaction rate.

- Exhibit de-emulsification properties for rapid clean up.
- Most reaction products are water soluble and easily removed.
- Additives to minimize or eliminate insoluble reaction products can be applied.
- In addition to the above advantages, 15% hydrochloric acid will also provide other specific properties such as emulsion and silt suspension.

The common uses for hydrochloric acid are as follows:

- Carbonate acidizing - Fracture and Matrix.
- Sandstone acidizing - Matrix only.
- Preflush for HCl: HF mixtures.
- Post-flush for HCl: HF mixtures.
- Acidizing sandstones with 15% to 20% carbonate content.
- Clean-up of acid-soluble scales.
- Perforation washes.
- Pure hydrochloric acid (muriatic acid) is a colorless liquid, but takes on a yellowish hue when contaminated by iron, chlorine, or organic substances. It is available commercially in strengths up to 23.5° Bé (Baumé scale) or 38.7% percent by weight of solution.

Reactions:

-with carbonates:

$HCl + CaCO_3 \rightarrow H2O + CO2 + CaCl_2$

-with sandstone:

$SiO_2 + 4HCl \rightarrow SiCl_4 + 2H_2O$

b) Hydrofluoric Acid (HF)

Hydrofluoric acid, another inorganic acid, used with hydrochloric acid to intensify the reaction rate of the total system and to solubilize formations, in particular sandstones.

In general, hydrofluoric acid is used as follows:

- It is always pumped as an HCl: HF mixture.
- Ensure that salt ion contact is prevented.
- Sandstone matrix acidizing.
- Removal of HCL insoluble fines.
- Normal concentrations are from 1.5% to 6.0%.
- One gallon of 12:3 HCl: HF will dissolve 0.217 pounds of sand.

Hydrofluoric acid exists as a liquid either in the anhydrous form (where it is fuming and corrosive), or in an aqueous solution (as used in well stimulation). Hydrofluoric acid attacks silica and silicates, (glass and concrete). It will also attack natural rubber, leather, or certain metals such as cast iron and many organic materials.

In well stimulation, hydrofluoric acid is normally used in combination with hydrochloric acid. Mixtures of the two acids may be prepared by diluting mixtures of the concentrated acids with water, or by adding fluoride salts (e.g. ammonium bifluoride) to the hydrochloric acid. The fluoride salts release hydrofluoric acid when dissolved in hydrochloric acid

.

Hydrofluoric acid is toxic, alone or in mixtures with hydrochloric acid, and should be handled with extreme caution.

Reactions:

-With Carbonates:

$CaCO_3 + 2\ HF \rightarrow CaF2 + CO_2 + H_2O$

-With Sandstone:

$SiO_2 + 4\ HF \rightarrow SiF_4 + 2\ H_2O$

c) Other Inorganic Acids

Some consideration has been given to using sulfuric and nitric acids; however, these acids are not used extensively in the oil industry today. The reasons for the lack of use are; sulfuric acid will form insoluble precipitates, and nitric acid often forms poisonous gases during its reaction with certain minerals.

2.2.2. Organic Acids

This type of acids are used in well stimulation basically because they have a lower corrosion rate and are easier to inhibit at high temperatures than hydrochloric acid. Although mixtures of organic acids are considered corrosive to most metals, the corrosion rate is far lower than that of hydrochloric or hydrofluoric acid, therefore, organic acids are used when long acid-pipe contact time is required. An example of this is when organic acid is used as a displacing fluid for a cement job. The organic acids are left in the production string and is subsequently used a perforating fluid. Organic acids are also used when metal surfaces of aluminum, magnesium, and chrome are to be contacted with, such as in trying to remove acid-soluble scales in wells with downhole pumps in place. They can also be used as iron control agents for other acid systems. Many organic acids are available, but the four most commonly used are:

a) Acetic Acid (CH3COOH)

Acetic acid is a colorless organic acid soluble in water in any proportion and in most organic solvents. Although mixtures of acetic acid with water are considered corrosive to most metals, the corrosion rate is still far lower than that of hydrochloric and hydrofluoric acids. Acetic acid is easy to inhibit against corrosion and is used regularly as a perforating fluid where prolonged contact times are required. With this ability, the acid is sometimes used as a displacing fluid on a well cementing job، where the contact time may be hours or days before perforating takes place. This ability is beneficial in three ways:

- It reduces formation damage. The first fluid to enter the formation will be an acid or a low PH fluid which will react with carbonate or the calcareous materials of a sandstone formation.
- It reduces clay swelling.
- Can be used where aluminum, magnesium or chrome surfaces must be protected.

The cost of acetic acid per unit, based on dissolving power, is more expensive than either hydrochloric acid or formic acid. Normally, acetic acid is used in small quantities or with hydrochloric acid, as a delayed reaction, or retarded acid.

The general uses and properties of acetic acid are as follows:

- Acetic acid is relatively weak.
- Normal concentrations of 7.5% to 10% when used alone.
- Mainly used in hydrochloric acid mixtures.
- Used as an iron control additive.
- Carbonate acidizing.
- Perforating fluid.
- Retarded acids.

Commercially available acetic acid is approximately 99% "pure". It is called glacial acetic acid because, ice-like crystals will form in it at temperatures of approximately 60° F (16° C) and will solidify at approximately 48° F (9° C). When glacial acetic acid is mixed with water, a contraction occurs. For this reason, the amount of acetic acid and the amount of water normally total more than the required volume.

Care should be exercised when handling acetic acid. This solution in concentrated form can cause severe burns and fume inhalation can harm lung tissue.

Reactions:

-With Carbonates:

$CaCO_3 + 2CH_3COOH \rightarrow Ca\ (CH3COO)_2 + H_2O + CO_2$

-With Sandstone:

$SiO_2 + 4CH_3COOH \rightarrow Si\ (CH3COO)_4 + 2H_2O$

b) Acetic Anhydride Acid

Acetic anhydride is the cold weather version of the Acetic Anhydride Acid, used instead of acetic acid due to its lower freezing point of 2.0° F (-17° C). The properties of acetic anhydride are the same for those of acetic acid, the only changes are those in relation to volumes used.

A comparison of acetic anhydride to acetic acid shows that one gallon of acetic anhydride mixed with 0.113 gallons of water is equivalent to 1.127 gallons of acetic acid. Expressed alternatively one gallon of acetic acid is equivalent to 0.887 gallons of acetic anhydride mixed with 0.101 gallons of water. When mixing acetic anhydride always add it to water or dilute acid. If water or dilute acid is added to acetic anhydride; an explosion will occur due to a rapid increase in temperature caused by the chemical reaction.

As with acetic acid, care should be exercised when handling acetic anhydride as this solution in concentrated form can cause severe burns and fume inhalation can harm lung tissue.

c) Citric Acid ($C6H8O7$)

Iron scales are normally found in the casing and tubing in wells and sometimes as the mineral deposits in the formation rock itself. When hydrochloric acid solutions come into contact with these scales or deposits, the iron compounds are partially dissolved and are carried in solution as iron chloride. As the acid becomes spent، the PH rises above 2.0, allowing the iron chloride to undergo chemical changes and re-precipitate as insoluble iron hydroxide. This re-precipitation can reduce formation permeability and injectivity.

Citric acid (Ferrotrol 300) is a white granular organic acid material used to "tie up" dissolved iron scales and prevent re-precipitation of dissolved iron from spent hydrochloric acid solutions. Normally, citric acid (often referred to as a sequestrant or sequestering agent), is used with X-14 to make the effects of suspension more stable.

Citric acid is not used alone as an acid treating solution itself but is used in hydrochloric acid solutions known as sequestering acids (SA-systems) for the control of iron.

The amount of citric acid added to the hydrochloric acid system depends upon the amount of iron that is present. The first 50 pounds of citric acid added to 1000 gallons of acid, will sustain 2000 parts per million (ppm) of iron in solution (SA-2). Each additional 50 pounds of citric acid added will increase its sequestering property by an additional 2000 ppm.

Iron re-precipitation depends upon the retention time of the acid in the formation and the PH of the spent acid solution. In dolomite and limestone formations, hydrochloric acid solutions can spend rapidly and as the PH reaches 2.0, the dissolved iron starts to re-precipitate. Therefore, it is important to start production or swabbing operations within an hour after the acid job is complete.

The procedure for mixing sequestering acid is as follows:

1. Place dilution water in the tank.
2. Add the citric acid and X-14 whilst agitating.
3. Blend until dissolved.
4. Add the inhibitor, surfactants, and finally add the raw hydrochloric acid.

In sandstone formations, if the acid solubility is low, the pH of the spent acid may stay below a pH of 2.0, and iron sequestering agents may not be needed.

Reactions:

- With Carbonates:

$2\ C_6H_8O_7 + 3\ CaCO_3 \rightarrow Ca_3\ (C6H5O7)_2 + 3\ CO_2 + 3\ H_2O$

- With Sandstone:

$C_6H_8O_7 + SiO_2 \rightarrow C_6H_6O_7Si + H_2O$

d) Formic Acid (HCOOH):

Formic acid is the simplest of the organic acids and is completely miscible (capable of being mixed) with water. Formic acid is stronger than acetic acid yet weaker than hydrochloric acid. Formic acid is used in well stimulation, most frequently in combination with hydrochloric acid as a retarded acid system for high-temperature wells. The percentage of formic acid used in such applications is commonly between 8 %0.and 10%.

Formic acid can be easily inhibited, but not as effectively as with acetic acid at high temperatures and long contact times.

The properties and uses of formic acid parallel those of acetic acid as stated below:

- Formic acid is relatively weak.
- Seldom used alone.
- Mainly used in hydrochloric acid mixtures.
- Corrosion inhibitor aid.
- Hot wells.
- Retarded acids.

Acetic acid, acetic anhydride and formic acid are used when exceptionally retarded acid is needed because of extreme temperature or very low injection rates. At high temperatures, blends of organic and hydrochloric acid are much more successfully inhibited by organic inhibitors, than when hydrochloric acid is used alone. This property minimizes the danger of hydrogen embrittlement of steel associated with hydrochloric acid treatments in high-temperature wells. Organic acid concentrations of up to 25% by weight are required, making acid treatment costs increase. Organic acids do not give as much reacting capability as hydrochloric acid treatments.

Reactions:

- With Carbonates:

$2HCOOH + CaCO_3 \rightarrow Ca\,(HCOO)_2 + CO_2 + H_2O$

2.2.3. Compound Acids

It is a mixture of both organic and inorganic acids mixed for the purpose of extending the reaction time in formations that can deal with low pressure operations

2.2.4. Retarded acid systems

HCl and HF are two acids reacting quickly with carbonates and silicates. However, the objectives of acid treatment are to increase porosity and permeability of the medium, deeply in the formation. Methods, which have been developed to slow the acidizing process, include:

- Emulsifying the aqueous acid solutions in oil (or solvents such as kerosene or diesel fuel) to produce an emulsion, which is reacting slower.
- Dissolving the acids in a non-aqueous solvent (alcohol, gel … etc)
- The use of non-aqueous solutions of organic chemicals which release acids only on contact with water.
- The injection of solutions of methyl acetate, which hydrolyses slowly at very high temperatures to produce acetic acid.

In addition to these methods, of which emulsifying the acid is probably the most important, some retardation of the reaction rate can be achieved by gelling the acid or oil wetting the formation solids. Gelled acids are used to retard acid reaction rate in treatments such as acid fracturing. Retardation results from the increased fluid viscosity reducing the rate of acid transfer to the fracture wall. However, use of the gelling agents (normally water soluble polymers) is limited to lower temperature formations as most gelling agents degrade rapidly in acid solution at temperatures above 55°C.

Some retardants can be added to the mud acid (HCl-HF mixture) to slow the reaction rate of acid with the minerals. A key is to inject a solution not containing HF explicitly but a compound able to generate HF at greater depth of penetration and longer reaction time for maximum dissolution of fines (Crowe et al., 1992). This retardant hydrolyzes in water when it enters in the reservoir to form HF according to the reaction:

$HBF_4 + H_2O \rightarrow HBF_3OH + HF$

Other retardant systems can be used as the emulsifying of the aqueous acid solutions in oil, the dissolving of the acids in a solvent (alcohol, gel…) or the injection of solutions of methyl acetate, which hydrolyses slowly at very high temperatures to produce acetic acid.

2.3. Acid Additives

2.3.1. Corrosion inhibitors

By the nature of its adsorption on solid surfaces, the corrosion inhibitor is a surface-active agent with a unique purpose that is to protect pipe rather than to change acid behavior in the formation. Corrosion inhibitors do not stop corrosion; they greatly reduce the reaction rate of acid with steel. Proper selection and application of corrosion inhibitors also reduce pitting (the tendency of acid to corrode or dissolve metal deeply in specific sites). Corrosion inhibitors are cationic and oil wetters. This is the mechanism by which they adsorb (plate out) on a metal surface and form an oil-wet film to protect the iron from exposure to acid. Plating out and oil wetting also occur in the formation, especially on clay minerals. To compensate for this, other additives, such as surfactants and mutual solvents, are used to restore water-wetness and maximize permeability to oil.

Pitting corrosion is very detrimental to the integrity of pipe. Reasons for pitting are inhibitor breakdown with time and temperature, insufficient inhibitor for wellbore conditions, and metal impurities in pipe.

Factors that affect corrosion are:

- Pipe metallurgy
- Type acid
- Acid concentration
- Temperature
- Inhibitor solubility in the acid
- Inhibitor concentration
- Contact time with steel
- Inhibitor aids
- Compatibility with other acids and additives such as organic acid, surfactants, alcohol, and solvent in the acid

Service companies perform extensive lab testing in combination with additives to provide data to estimate the time of protection of pipe during the course of acid exposure to tubing in an acid treatment. The type of inhibitors and conditions in which they are used are many and complex. The engineer works closely with the stimulation specialist to ensure the proper selection and use of corrosion inhibitors in oil/gas wells. Usually, less than 5 mils of tubing corrosion should be allowed by the inhibitor in an acid treatment (equivalent to 0.025 lbm/ft^2 of tubing surface area) at temperatures less than 200°F.

2.3.2. Surface active agents (Surfactants)

Surface active agents are molecules composed of an oil-soluble group and a water-soluble group. These chemicals lower the interfacial tension between the immiscible fluids. They also adsorb on rock surfaces and can alter the natural wettability of rock. Surfactants are classified into four major groups depending on the nature of the water-soluble part of the molecule.

These divisions are:

- Anionic (water-soluble end is anionic)
- Cationic (water-soluble end is cationic)
- Nonionic (do not ionize—one end of molecule is water-soluble, the other is oil-soluble)
- Amphoteric (water-soluble end may be anionic, cationic, or uncharged depending on the pH of the system)

The primary use of surfactants is in emulsion prevention in acid/oil interactions. Other uses are as:

- Wetting agents
- Penetrating agents
- Sludge preventers and foaming agents
- Acid solvent dispersant
- Mud dispersants
- Emulsion breakers
- Retarders
- Suspending agents

Surfactants should be tested for performance as emulsion breakers for crude/oil acid systems in both live acid and spent acid.

2.3.3. Alcohol

Methyl alcohol and isopropyl alcohol have been used for many years to aid in cleaning up water-blocked gas wells. On occasion, 10 to 20% alcohol is used in acid to stimulate moderately low-permeability (5 to 50 mD) gas sands to speed the cleanup of spent acid.

2.3.4. Clay stabilizers

Clay minerals or other fines may move in the formation, particularly during water production. Also, some clays can be dispersed or swell when contacted with fresh water or low-salinity brines.

Cationic polymers are sometimes used in brine or acid to stabilize clays. These cationic polymers do not oil-wet sands, because the end of the molecule projecting from the adsorbed end is water soluble.

Clay stabilizers used include:

- Polyquaternary amines
- Polyamines
- Cationic surfactants

Polyquaternary amines have been the most effective, with polyamines second. The use of cationic surfactants for clay control is not recommended except in water-injection wells in water-sensitive formations. A wide variance in opinion exists as to how to best apply these products. Clay stabilizers are most often used in the overflush following an HF-acid treatment in sandstone formations. Most of the clay stabilizers are not affected by HCl acid but are dislodged by HF acid. It is not recommended to use more than 20 gal/1,000 gal.

2.3.5. Calcium sulfate inhibitors

When acidizing formations with a high-sulfate-ion content in the formation water (usually greater than 1,000 ppm) or rock containing anhydrite, it is advisable to include a calcium sulfate inhibitor in the acid. The inhibitor is usually phosphoric acid, polyacrylate, or other material.

2.3.6. Gelling agents

Acids may be thickened for diversion during acidizing with soluble polymers such as xanthan (a biopolymer) or acrylamide polymers. Higher viscosity may be obtained with crosslinking metal ions or ligands. Certain surfactants may be used to thicken acid through the formation of surfactant micelles.

2.3.7. Mutual solvents

A mutual solvent is soluble in either oil or water. For this reason, it is very effective in sandstone acidizing, in which it is important to keep all solids water-wet. Mutual solvents are either EGMBE or other modified glycol ethers. They improve the solubility of corrosion inhibitors in the spent acid in the formation and compatibility of inhibitors with emulsion preventers and other additives. The most important property is to reduce the adsorption of corrosion inhibitors on residual clay particles in the formation and to help maintain water-wetting for maximum oil/gas flow after acidizing. A mutual solvent also reduces residual water saturation (spent acid) following a treatment. Gas wells clean up better by keeping surfactants in solution rather than adsorbing on sand and clay too near the wellbore.

2.3.8. Iron-control agents

Iron control uses several different products to keep iron in solution:

a) Iron-complexing agents: -

Iron in solution has two forms:

1. Ferric
2. Ferrous

Ferric iron is often called iron (III), and **ferrous** iron is often called iron (II). The oxidized form, iron (III), precipitates in spent acid around a pH of 1 to 2. Iron (II) does not precipitate as ferrous hydroxide until a pH of 7 is reached, well beyond the final equilibrium of spent HCl acid, which is around a pH of 5. Normally, the ferrous iron is not a problem in acid treatments; however, there are three exceptions. If acid is pumped into a new well that has been drilled with caustic water-based mud, the mud filtrate in the formation may still have a pH of 11 or higher. Mixing of spent acid with this mud filtrate precipitates ferrous hydroxide. Ferrous iron also precipitates in a sour environment where hydrogen sulfide is dissolved in the brine, oil, or natural gas. The only effective remedy to keep iron (II) in solution where hydrogen sulfide exists is to use a hydrogen sulfide scavenger to make the sulfide unavailable for precipitating ferrous sulfide at a pH of 2. Complexing agents do not prevent the precipitation of iron sulfide. A third problem long term is the presence of iron (II) in the presence of undissolved calcium carbonate. Iron (II) can precipitate slowly as ferrous carbonate a slowly forming carbonate scale. This usually does not impede flow in carbonate rocks but may in sandstone with excess carbonate because the sand grain matrix can screen the precipitate. Addition of acetic acid to the Preflush maintains a low-pH environment to prevent the iron carbonate precipitation.

Ferric oxide and ferrous sulfide are frequently found in water-injection wells in surface pipe, tubing and borehole, and in the formation. The iron oxide is present from air contamination in the injected water. Iron sulfide is present from bacterial action in the injected water or formation. Ferric oxide is common in all acid treatments. The main source is a coating of mill scale or rust on the surface of the tubing or piping used in stimulation. This is usually the source of the most damaging iron concentrations in acid. Iron-complexing agents can only complex iron concentrations of up to 10,000 ppm. Acid can dissolve iron from tubing walls as high as 100,000 ppm. No complexing agent can complex this much iron. Two important steps in controlling iron in acidizing are pickling treating strings prior to acidizing and using iron reducing agents. Acid pickling treatments are covered later in the section on job execution; however, the purpose of pickling tubing is to clean the tubing of easily dissolved iron and bring it back to the surface for disposal. This procedure reduces the amount of ferric iron in solution during the subsequent injection of acid into the formation.

b) Iron-reducing agents

The most common iron-reducing agent is erythorbic acid a cousin to vitamin C. Erythorbic acid is added to the acid to reduce any ferric ion to ferrous iron before it enters the formation. The use of a reducing agent does not take the place of acid pickling the treating string. Even though pickling removes most of the easily dissolvable iron oxide from the tubing, enough iron oxide remains after pickling so that a reducing agent is still necessary during the acid treatment. Some formations contain iron oxide in the formation so that iron complexing agents are still needed along with the reducing agent as a safeguard. One of the favorite iron-control agents is the combination of citric and acetic acid. Citric acid by itself is limited to 15 lbm/1,000 gals of acid because of limited solubility in the acid. Acetic acid permits mixing higher loadings of citric acid (up to 100 lbm/1,000 gal) and also maintains a low pH in spent acid to keep iron (III) in solution. Improved techniques and procedures have advanced the control of dissolved iron in acid treatment.

c) Hydrogen sulfide control

Common chelating agents are ineffective for iron control in sour environments. Systems containing hydrogen sulfide contain only ferrous iron [iron (II)] species. The only effective method of preventing precipitation of iron sulfide during sour-well acid treatments is to remove hydrogen sulfide from the fluid with sulfide scavenger products. If there is any possibility of ferric iron [iron (III)] being injected from surface containers or pipe, a reducing agent should be added in the acid to reduce the dissolved iron (III) to iron (II).

2.4. Acid Selection for Carbonates and Sandstone Formations

2.4.1. Acids for carbonate formations

The most common used acid in carbonate acidizing is (HCL) as it reacts readily with carbonate minerals and is available in large quantities at a relatively low price. Whereas the purpose of sandstone acidizing is to dissolve the damage, acid is used in carbonate formations to dissolve the matrix and bypass the damage. For this reason, both damage and rock characteristics must be taken into account when designing the treatment.

The main reaction:
$CaCO_3 + 2HCL \rightarrow CaCl_2 + CO_2 + H_2O$

2.4.2. Acids for sandstone formations

Sandstone matrix acidizing is distinguished from carbonate acidizing in that it involves the dissolution of damage that is blocking or bridging the pore throats in the formation matrix, thus ideally recovering the original reservoir permeability. Because the formation and the damage can have complicated crystalline structures that can yield a variety of reaction products, sandstone acidizing success requires a significantly better understanding of chemistry than does carbonate acidizing. To conclude, Sandstone matrix acidizing is distinguished from carbonate acidizing in that it involves the dissolution of damage that is blocking or bridging the pore throats in the formation matrix, thus ideally recovering the original reservoir permeability.

The main reaction:
$SiO_2 + 4HF \rightleftharpoons SiF_4 + 2H_2O$

2.5. Acid Diverting Systems

Diversion is the process by which the treating fluid is diverted from high permeable zone and allowed to enter the lower permeable zone, thereby making the homogenous distribution of treating fluid in the zones of interest. A critical factor to the success of an acidizing treatment is proper placement so that designed volumes of treating fluids contact productive intervals. Effective placement of the treating /stimulation fluids evenly across the zones of interest is important specially when treating long perforated intervals or multiple zones. If there are significant variations in reservoir permeability, the acid will tend to flow primarily into the highest- permeability zones, leaving lower- permeability zones virtually untreated. Even in relatively homogeneous formations, the damage may not be distributed uniformly without the use of techniques to improve the acid placement; much of the damage may be left untreated. Thus the distribution of the acid into the formation is an important consideration in matrix acidizing, and treatment design should include plans for uniform acid placement.

2.5.1. Chemical Diversion

a) Viscous Fluid System

Scientists have developed many types of Acidizing services to suit the issues that may be encountered during acidizing. In terms of gelled acid system, they studied commercially available polymers to figure out which one was suitable at high temperature areas. In situ cross-linked acids (ICA) are the first generation of gelled acids designed for diverting acids at high temperatures. The ICA contains a gelling agent, cross-linker, a buffer, and a cross –linker breaker. There are also other types of viscous systems like emulsified acid, viscous slug or self-diverting agent.

Moreover, in situ cross-linked acids can be affected by any increase in pH by completely spending the acid that can cause the cross-linker breaker to activate; then, the in situ gelled acid breaks down as well as its viscosity drops to values close to that of water to assist easy flow back. However, since the system has polymers, the bulk fluid viscosity is reduced (there is still polymer residues) which can plug the face of the wormholes. To avoid this problem, a second generation of gelled acids was developed which is the viscoelastic surfactants (VES).

Viscoelastic surfactants (VES) system or (self-diverting system) uses a single component, that forms rod-like micelles in situ when pH increases due to acid spending, and the viscosity drops when hydrocarbons contact the fluid during the flow back. The surfactants leaves no residue on the wormhole surfaces and requires very low clean up pressures. Because of its ease of clean up, viscoelastic surfactants based in situ gelled acids can have a prolonged viscosity build up with no need to break back until the hydrocarbon flow back. This prolonged buildup of viscosity provides additional benefit over the polymer-based in situ gelled acid with sustained diversion.

The in-situ cross-linking acid diverting agent (ISCADA) is another viscous system which is sensitive to both PH and temperature sensitive. This diverter chemical with maintained PH is cross-linked at reservoir temperature. The cross-linked, high viscous diverting agent then blocks the subsequent treating fluid to enter into the high permeable layer and divert them to the zone of interest. The alternating stages of diverting agent, retarded acid and main acid can be designed as per the well condition.

b) Nitrogen/Foam Energized Acid System

A foam is a stable mixture of liquid and gas that is made stable by using a surface active agent (surfactant). This agent concentrate at the gas/liquid interface and lowers the interfacial tension. The surfactant also stabilizes thin liquid films and prevents the cells from coalescing. Foam is used also to eliminate the need for extensive acid reaction rate retardation, remove formation fines. Moreover, the foam viscosity can be very high (depending on the shear rate).

Nitrogen pumping system can also be used alongside coiled tubing lift fluids and in cleaning out the wellbore, it also can be used in cementing to generate foamed cement. Additionally, if the wells have a low API gravity, foamed acid can remove any heavy deposits (asphaltenes or paraffines), and allow the acid to react with the formation face, it can also allow the solvent to soak for several hours (4 hours) before commencement of the acid treatment. Likewise, foamed acid is useful when it comes to wells with scales problems as it acts as a cleaning agent.

c) Particulate Diversion Technique

Fine particles are added and placed against the high permeability or less damaged zone. This mean of diversion creates a relatively low permeability filter cake on the formation face of high permeability zone. Moreover, this filter cake resist flow of reactive fluid to high permeability zone and divert the fluid to zone of interest

2.5.2. Mechanical Diverting System

a) Zone Isolation

It is a process that focuses on the usage of some isolation equipment used to select a specific zone for the purpose of treating it.

The main means for isolation are:

1. Straddle Packer thru Tubing
    - It is a packer that is usually used to treat multiple zones completion or stimulation. Moreover, the injection starts in the lowest zone and then moves to the upper ones zone by zone.
2. Inflatable Packer thru Coiled Tubing Unit.
    - It is another type of packers that is used for single well completion and stimulation. This type of packer has a one way valve that injects the fluid to the zone and make sure it does flow back.
3. Other types of packers.

b) Ball Sealers

Ball sealers are rubber-coated balls that are designed to seat in the perforation. The reactive fluid carries the balls and place the perforation tunnel of high permeability so it can block them, and then divert the acid to another intervals. In this type of diversion, both buoyant and heavy ball sealers are used

2.6. Acidizing Equipment

2.6.1. Acidizing Pump:

The usual used pump is the 1200 Hydraulic Horsepower Trailer Mounted Twin Pump that has a maximum rated of 16.5BPM and maximum pressure of 15000 PSI. The Trailer mounted twin pump unites with dual 600 HHP triplex well service pumps for a combined rating of 1200 HHP. Triplex pump with 3 in. plungers for a maximum working pressure of 15000 PSI. On the other hand, triplex pump with 4 in. plungers for a maximum rate of 10.5 BPM. Pumps can be operated simultaneously to achieve a maximum discharge rate of 16.5 BPM.

Figure 1-4 Acidizing Pump

2.6.2. Fluid Handling Equipment:

There are many equipment used like:

- 1 BBL inventory tanks with paddle wheel agitators.
- 1 BBL mixing tub with jet system and dedicated centrifugal pump for mixing rock salt, sand, and chemicals slurries on-the-fly.
- High pressure dual discharge manifold mounted at the rear of the unit to control the discharge flow of either or both pumps.

All the systems on the twin pump unit are operated and monitored from a climatized control cabin, where job data is displayed and recovered via the DP600 Data Logger data acquisition system.

2.6.3. Acid Handling Equipment:

There are many equipment to use like:

- Dual compartment 5000 gallon acid transports.
- Trailer mounted acid transports that have a 120 BBL capacity with 2500 gallon compartments.

- Fluid handling system that includes a Mission 3 in. X 4 in. centrifugal pump and roll lines for mixing and rolling acid and chemical diverter.
- Trailer type mobile 500BBL Acid frac tanks provide adequate storage for acid, chemicals, and fluids at the well site.

2.7. Treatment Equipment Identification:

2.7.1. Coiled Tubing:

Coiled tubing (CT) is a generic name often used for coiled tubing services (CTS). Operationally, a CT intervention involves pushing a coiled tubing string into an oil or gas well to perform work without disturbing the existing well completion. The ability to pump through the CT string allows many different types of operations be carried out. At the end of a CT operation, the CT string is pulled out of the well and spooled back onto the CT reel. CT technology is based on the use of the CT string, which is a continuous flexible steel tube that is spooled on a reel for transport and storage. The reel is a part of the coiled tubing unit) CTU).

At surface, the end of the CT string is connected to a high-pressure swivel joint on the reel hub so that fluids can be pumped through the string continuously if necessary. The CT string is run into and retrieved from the wellbore by the injector head. The injector head is controlled hydraulically from the CT cabin by the CTU operator. The hydraulic system gives the operator a high degree of control over the position and movement of the CT string. Moreover, a stripper assembly is mounted below the injector head. This assembly provides a dynamic seal around the tubing string, which means that the CT string can be run and retrieved on live wells.

The blowout preventer (BOP) assembly is mounted between the stripper and the wellhead. This provides secondary and contingency pressure control functions. Additionally, the CTU is operated from the control cabin, which is designed as a single point control and monitoring station for the primary functions of the CTU and auxiliary equipment.

Figure 2-1. CTU Terms

Figure 2-4 Coiled Tubing Unit

Regardless of its function and/or working environment, a coiled tubing unit (CTU) will include the following main components:

a) Prime mover or power pack:

The prime mover or power pack is usually a diesel engine that provides power to the hydraulic circuits in a Coiled Tubing Unit.

The major components of the power packs include the following:

- Engine.
- Hydraulic pumps.
- Pressure-control valves.
- Hydraulic Reservoir.
- Accumulators.
- Filters and strainers.
- Heat exchangers.
- Hydraulic fluid.

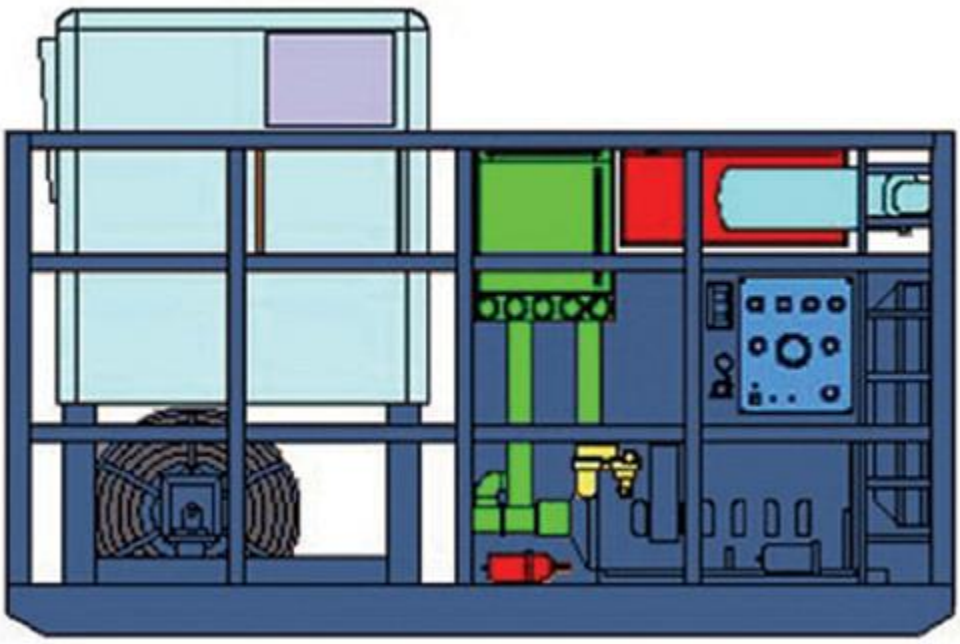


Figure 2-5 Power Pack with Integral Control Cabin

b) .Control cabin or console

Depending on the configuration of the CTU, the control cabin may be contained on a separate skid, be incorporated with the power-pack skid, or be permanently truck mounted. Regardless of its configuration, the control cabin is generally situated behind the CT reel, in line with the wellhead/injector head.

The control cabin contains all necessary controls and instruments to allow the CT operation to be run from one control station. In some instances, controls and instruments for associated services (e.g., pumping) are also located in the CTU control cabin .

The instruments and control systems in the control cabin can be categorized as follows:

- Primary instruments and controls
- Weight Indicator, Circulating and Wellhead Pressure.
- Secondary instruments and controls
- Depth/Speed, Chain Tensioner Pressures, Stripper Pressure.
- Support instruments and controls
- Drive System Pressures, BOP system Pressure, Engine RPM, and Air Pressure …etc.

Manual pumps for standby or emergency use on essential hydraulic functions are also located in the control cabin. These include manual or air-driven pumps to energize the BOP, stripper, and skate-tension circuits, so that well security can be maintained in the event of a major equipment failure .

Figure 2-6 Control Cabin

C) Tubing Reel

The primary function of the CT reel is to store and protect the coiled tubing. The reel also incorporates equipment that performs several functions which, though less obvious, are equally important to the successful operation of the coiled tubing unit.

These include :

1. Reel Drive System (1)
   - Maintains proper tension between the reel and injector.
2. Levelwind Assembly (2)
   - Ensures close, even and efficient spooling of the CT string back onto the reel drum.
3. Reel Swivel (not shown)
   - Allows fluid to be pumped through the reel while it is rotating.
4. Tubing Lubrication System
   - Application of inhibitor or protective coating.
5. Mechanical Counter
   - Backup CT depth measurement system.
6. Crash frame
   - not shown for clarity, but an important feature due tothe manner in which many reels are handled and transported

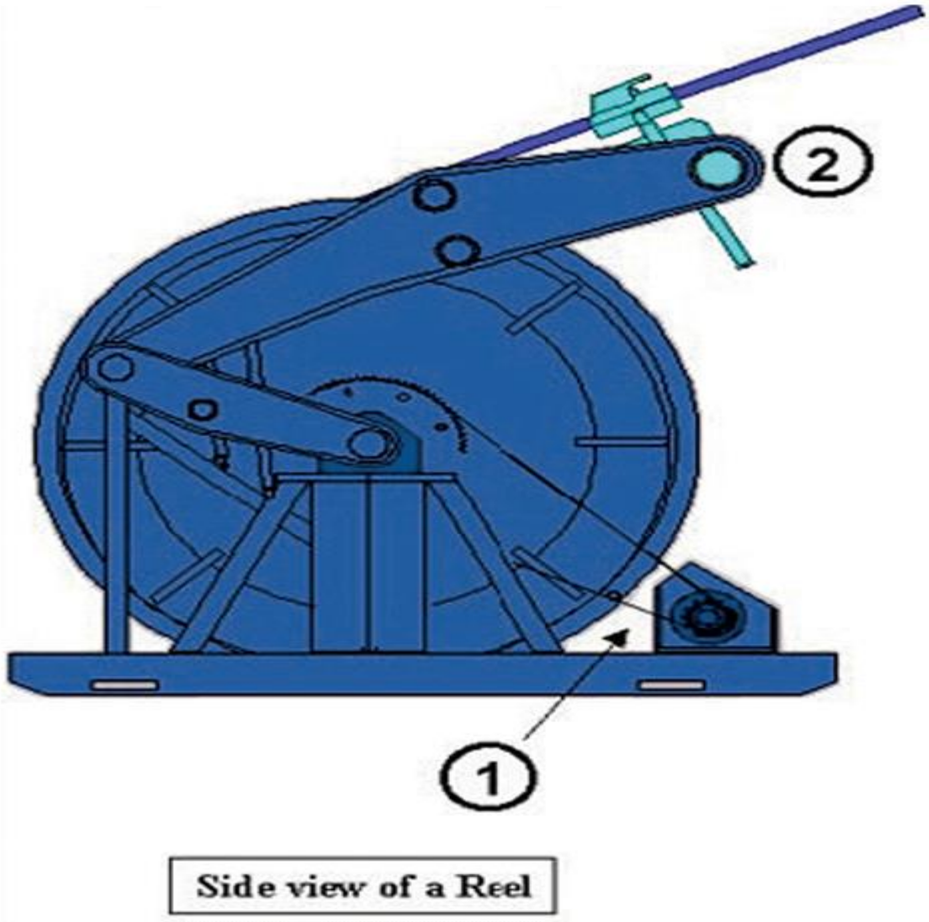


Figure 2-7 Tubing Reel

- **Levelwind**

The levelwind system provides automatic spooling. A manual override enables the CTU operator to make small adjustments when necessary.

The drive for the levelwind system is taken from the reel axle by chain drive or closed hydraulic system. The example shown illustrates an earlier reel model with chain drive (1). The levelwind head (2) follows a lead screw, which is rotated by the levelwind drive system. The hydraulic motor (3) is activated (forward or reverse) to advance or retard the lead screw. A slip clutch on the lead screw enables this action without affecting the drive system.

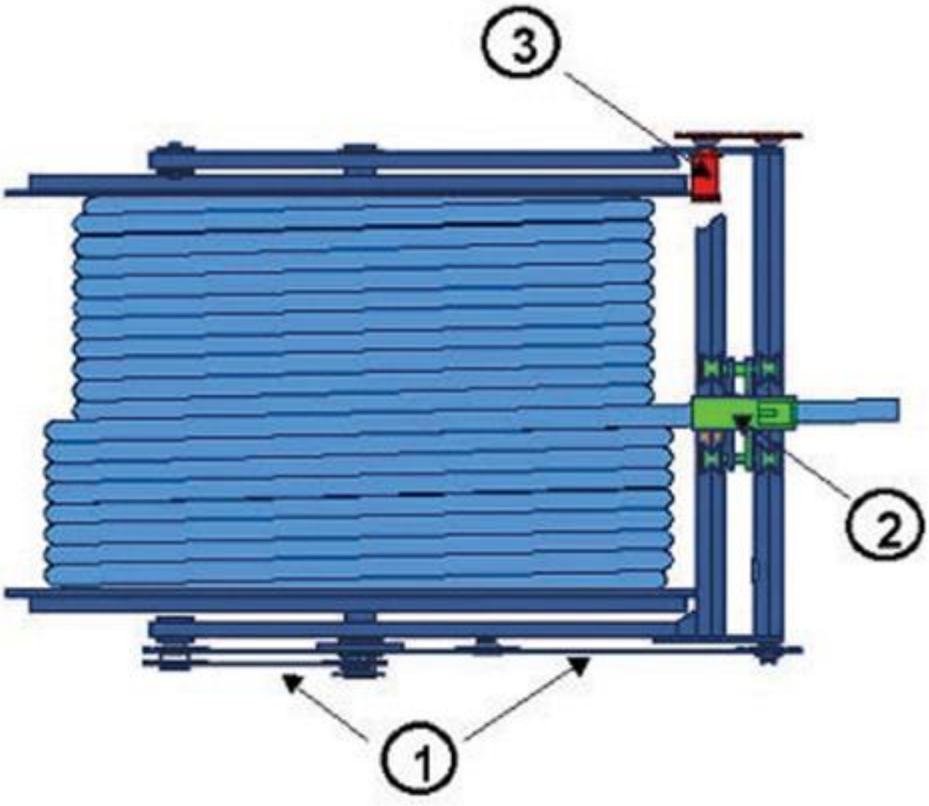


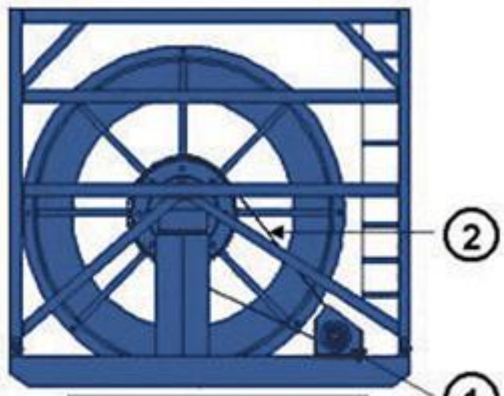
Figure 2-8 Levelwind

.

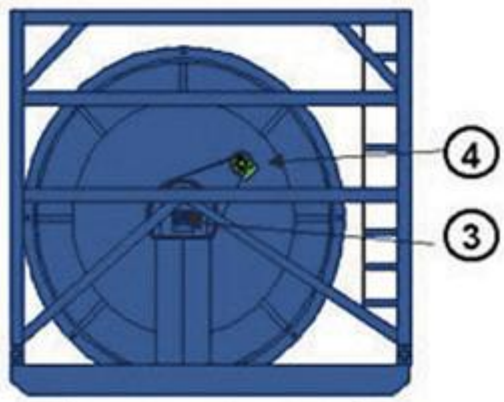
d) Reel Drive System

There are two configurations of reels in service in Schlumberger today. These are:

1. Right-Angle Drive – also known as a "conventional" reel – is configured with the reel motor (1) connected to the drum through a chain drive (2).
2. Direct Drive – sometimes called a "dished-end" reel, this model features a dished end drum construction which allows greater drum width and hence greater pipe capacity. The motor in this case in mounted directly onto the reel axle (3). Since this alignment does not allow for chains to be run between the reel axle and levelwind, a supplementary hydraulic system (4) is included for the levelwind drive.



Floor mounted Reel Motor



Axle Mounted Reel Motor

Figure: 2-8 Reel Drive System

e) Tubing Injector head

The injector head guides and powers the tubing string in and out of the hole. The tractive components of the injector head are generally configured to drive two opposing endless chains on which are mounted a series of short gripper blocks. The gripper blocks are shaped to the size of the tubing being used, and the chains are pressed together with the tubing held between. The total load of the CT in the well is held by the friction of these blocks. Hydraulic motors drive the chains, thereby allowing the tubing to be run in or out of the wellbore.

Major injector-head components include :

1. Injector drive motor (1).
2. Gooseneck or guide arch (2).
3. Inside Traction and Outside Chain Tensioners (3).
4. Drive Chains (not shown).
5. Stripper Mounting (4).

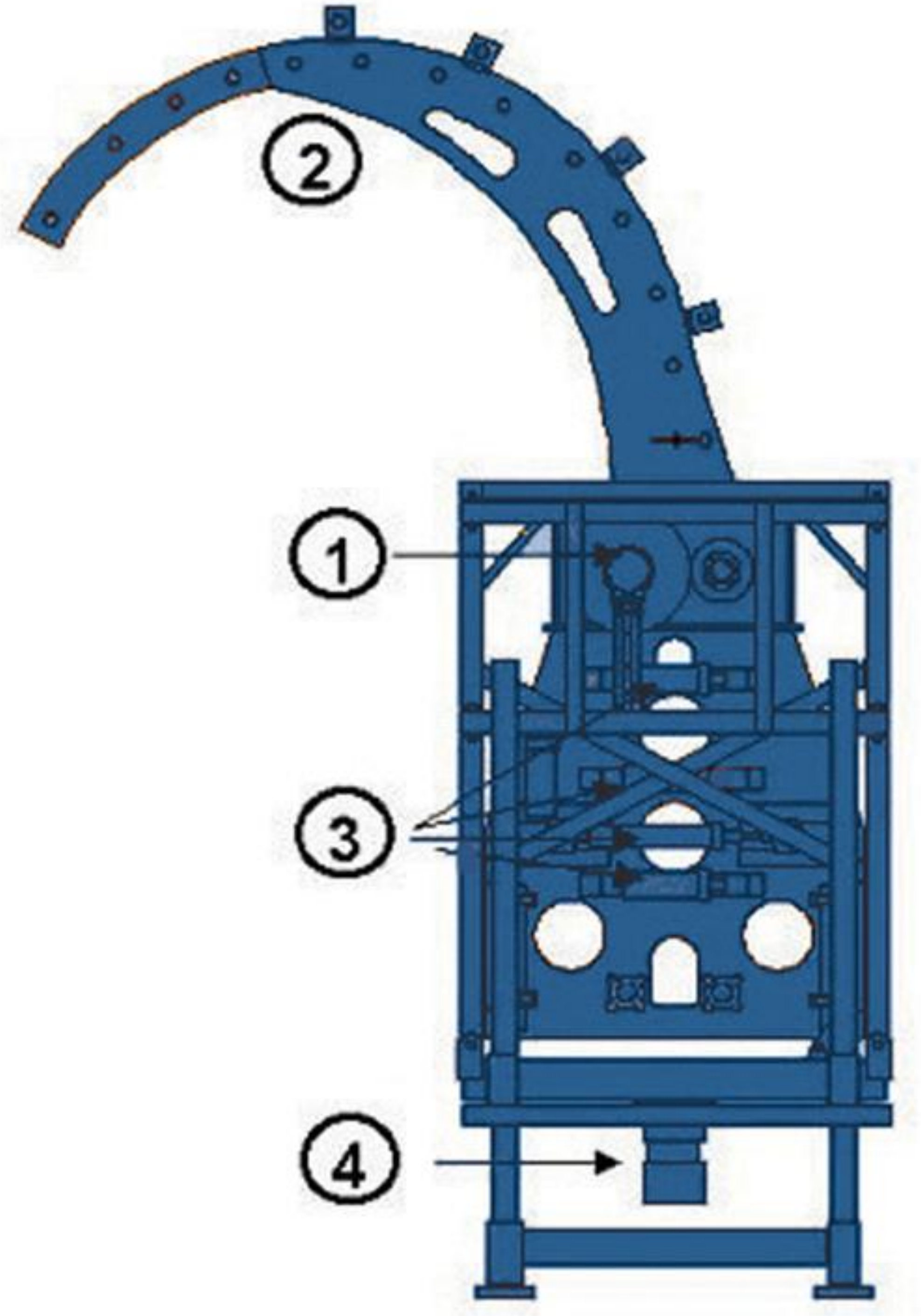


Figure 2-9 Tubing Injector head

2.7.2. Pressure-control equipment

Coiled tubing pressure control equipment can be described as the items of equipment necessary to preserve the integrity of the well (confine pressure) during normal CT operations. Depending on the Wellhead pressure encountered, there is both conventional and high-pressure coiled tubing pressure-control equipment.

The pressure control equipment to use are:

- Blowout Preventers.
- Stripper (Conventional, Side-Door, Radial Stripper).

2.7.3 .Downhole Tools and Equipment

The downhole tools and equipment required for any coiled tubing application are dependent on the complexity and specific conditions under which the operation is to be completed.

The most common downhole tools associated with conventional CT applications are:

- Connectors
- Check valves
- Nozzles.

2.7.4 .Zone Isolation Tools

Zonal isolation refers to operations where the primary objective is to isolate a section of the wellbore that needs to be treated. It is achieved through packers, which provide mechanical isolation between two zones

The main types of packer systems used are:

1) Cup-type packers

Cup-type packers, are the simplest type of packers, this packer is often set across a set of perforations to pump a treatment fluid, such as acid. The cup system isolates one section of wellbore and ensures that the fluid treats the selected perforations .

When fluid is pumped through the CT string, it exits the ports between the cups. The differential pressure across the cups forces the fluid to the tubing wall and provides a seal, forcing the fluid into the perforations. The cups relax again, then pumping stops.

These packers are only used in shallow wells. The cups wear as they rub along the inside of the tubulars and are damaged by nipple profiles. The cups do not expand; therefore, they cannot be set in a casing that is larger than the tubing above it. Cup-type tools are often used for Coil FRAC applications.

2) Mechanical packers (tension/compression set)

Mechanical packers require the tool string to maintain an adequate load on the packer to keep it set. Depending on the packer, the load can be tension or compression. These packers are often used to hang CT velocity strings or tailpipe extensions in a wellbore. The weight of the CT string hanging below the packer keeps it in tension and set.

3) Hydraulic set packer

The majority of hydraulic packers being used are double grip, which means that they include two sets of slips to grip in both directions. Typically, setting these packers is achieved by increasing the internal pressure compressing the sealing element and forcing the slips outward. As the packer sets, the shifting mechanism is held in place by a body lock ring, or ratchet, so that when the pressure differential is released, the packer stays set. To retrieve the packer, vertical pull will shear release screws or pins, allowing the slips and element to retract. Hydraulic set packers are being used extensively in gravel packs, patches, and gas lift installations.

4) Inflatable packers

Through-tubing inflatable packers, are designed to seal in a casing section that is larger than the tubing above it. The packer needs to be small enough to run and retrieve through the tubing, but when set, it expands to two or three times its original diameter. The higher the expansion, the lower the pressure differential it can withstand. Single-set inflatables are most commonly used as bridge plugs or isolation tools. Multiple-set inflatables can be set several times in one run and are ideal for remedial and stimulation operations or testing. When pressure is applied to an inflatable through the CT string, hydraulic valves trap the setting pressure in the inflatable element, holding the packer in place even when the tubing pressure is reduced. A straight pull allows the pressure to release and the packer element to relax for retrieval. Inflatable packers can be used as retrievable bridge plugs, cement retainers, or treatment packers.

2.8. Oil and Aquifer Influence on Acids:

When the acidic liquid enters the layer, it interacts with the rock as well as with the fluids in the layer (oil and water), and the reaction of the acid with the oil leads to the formation of insoluble compounds that are placed in the pores and channels of the layer. As a result, it leads to reducing the permeability of the layer. These compounds that reduce the permeability of the layer are (asphalt, resins, paraffin, and some hydrocarbon derivatives of large molecular weight) which are placed at high pH of the acid liquid. This situation can be prevented by two ways:

- The use of an acidic emulsifying liquid treated with aromatic solvents.
- Treating the acidic liquid with substances that prevent the formation of taric acids, such as activators

On the other hand, the reaction of the stratified water with the acidic liquid injected into the layer leads to the formation of some insoluble compounds, partially and sometimes completely closing the pores of the productive layer. This leads to a reduction in the actual permeability of the layer, and this effect is related to the chemical composition of the stratum water.

Of the electrolytes in the water that affect the acidification process, we mention:

- Iron and aluminum ions that form with the acid precipitated iron and aluminum water.
- Barium ions that form with the sulfate ions are dissolved barium sulfate.

2.9. Acidizing Damage

If the acid treatment is not used correctly and accurately it can cause damage to the formation.

Acidizing damage mechanisms include:

- Inadvertent injection of solids.
- Use of incompatible additives or improper mixing procedures.
- Precipitation of acid reaction products.
- Loss of near-wellbore formation compressive strength.
- Formation of emulsions.
- Formation of sludge.
- Water blocking.
- Wettability alteration.
- Post-treatment fines migration.

CHAPTER THREE

3. METHODOLOGY

3.1. Introduction

This research is focusing on applying a treatment process to the field of interest (Al-Tawila block-14) by an acid stimulation process. Production history data alongside other field data will be the source for applying the acid stimulation study. The reservoir rock properties of the field of interest will be taken under consideration alongside other useful parameters by using different analysis techniques

Moreover, geology is a major science in any petroleum adjustment process. The information and interpretations that come from geological studies are vital to whatever action needs to be applied on any field. Accordingly, the more accurate and better quality the data and the analysis are the better results will be attained.

3.2. Type of Data Required for the Study

The data needed for a perfect stimulation application are listed in **Table 3-1**

Table 3-1 Data needed for the Project

Acid Stimulation study requires the following data:	
No	Data Required
1	Production Report
2	Geological Report
3	Logging Data
4	Pressure Data
5	Mineralogy Data
6	Petrophysical Data
7	Hole Deviation
8	Completion Data

3.3. Analytical Approach

Both qualitative and quantitative analytical and descriptive approach will be conducted in the study. The reservoir available data will be studied and analyzed in order to use them in the right stage or formula. Additionally, previous scientific papers, researches, books and studies regarding the same topic will guide us to continue the study as accurate as possible.

3.3.1. Workflow Design

- Identify the layer of interest.
- Identify the acid fluids mixtures (treatment acid and additives) with their usage for each stage in the stimulation process.
- Determine treatment placement (diversion) method
- Conduct the acid stimulation to ensure proper treatment execution and quality control.
- Evaluate the treatment.

3.4. Expected Results

After the analysis for the available data, it is expected to perform an acid stimulation treatment in Al-Tawila field on Block-14 that will be done by evaluating the data of a single well (Tawila-70).

The accurate analysis for the available data alongside the correct workflow illustration will result in a good stimulation study for the chosen well and formation; however, the study will be as accurate as possible to be applied on the layer of interest despite of the lack of data and the absence of real field experience. However, an increase in the productivity index and a decrease in the skin factor are the main goal of the treatment.

CHPTER FOUR

4. DISCUSSION AND ANALYSIS

4.1. Introduction

Well stimulation may be carried out immediately after the initial drilling/ completion program has finalized to correct formation permeability impairment used by the drilling mud. Stimulation can also be applied on a damaged well when the cause of damage is regarding the permeability due to the formation of plugging materials that affect the productivity of the well negatively. Alternatively, the stimulation candidate may be identified as a result of routine, field production surveillance.

Table 4-1 Minimum Matrix Treatment Candidate Well Selection Criteria

Parameter	Oil Reservoir
Hydrocarbon Saturation	> 40%
Water Cut	< 30%
Permeability	> 30 mD
Reservoir Pressure	< 70% depleted

4.2. Candidate Selection:

Selecting the right candidates, with the right amount and concentration, is the key to a successful stimulation process. Moreover, the right selection involves two stages:

1. The identification and (accurate) quantification of those parameters, which control the productivity of a chosen well.
2. An analysis to determine whether the well stimulation treatment would actually improve the production of the chosen well.

Acid (inorganic) and solvent (organic) washes are the right chemical treatment type for removing restrictions. However, the product created by the chemical reaction between the acid and the formation rock can be insoluble in the spent stimulation fluid. This process is called secondary precipitation. As a result, this precipitation process leads to blockage of the prose and pore throat (impairment). Moreover, this precipitation often does not occur immediately – this implies that there is an opportunity to either:

1. Produce the (spent) acid (return to well production) or
2. Inject the acid deep into the formation where any participation will have limited effect on the will productivity.

Additionally, it must be checked that the injection fluids are compatible with each other and with the formation fluids.

4.3. Stimulation Sequence

1. Set the coiled tubing unit with the right specifications (2 inch tubing diameter, with an 84 inch for guide arch radius).
2. Set the selected packer (Inflatable packers) at the right depth (5920-5930 ft), and the packer should be longer then the perforation height at least 11 ft.
3. Prepare the acid mixtures in a separate tanks depending on the stage of injection.
4. Start with the (345.8752Gallons) preflush injection stage at a rate of (0.76 bbl/min) and injection pressure of (1154.88 psia), following it with a (3801.116671 gallons) of main acid mud and then (4603.3688 gallons) of overflush fluid.
5. Close the well and keep the acid so it could soak for (170) minutes.
6. Resume the production to the dump so it will not go to the separator until the ph of the product is the oil ph (all the spent acid is out of the formation).
7. Conduct well tests like (Build-up test) to check the changes in the productivity index PI (it should be higher than the previous value of 6), and the skin factor S (it should be less than the previous value of +2.7).

4.4.1. Preflush:

A preflush is a fluid stage pumped ahead of the main treating fluid. Multiple preflush stages are sometimes used to address multiple damage mechanisms and prepare the surface for the main treatment fluids. In sandstone reservoirs, the acid preflush, performed most often with an HCl solution, serves two purposes:

1. To displace the formation brines, usually containing K, Na, or Ca ions, away from the wellbore so there will be no mixing with HF acids. This decreases the probability of forming alkali-fluosilicates such as potassium hexafluorosilicate.
2. To dissolve as much of the calcareous material as possible, prior to injection of the HF acid to minimize calcium fluoride precipitation.

Table 4-2 Preflush concentrations

Fluid	Concentration	Volume
HCl	**7.5%**	**25.94064 Gallons**
Iron Control Agent NTA (FE-1A sequestering agent)	**1%**	**3.458752 Gallons**
Corrosion Inhibitor(HAI-85M)	**1%**	**3.458752 Gallons**
Clay Stabilizer (NH_4Cl)	**5%**	**17.29376 Gallons**
Surfactants (LOSURF-259)	**0.8%**	**2.7670016 Gallons**
Mutual Solvent (EGMBE)	**10%**	**34.58752 Gallons**
Water	**74.7%**	**258.3687744 Gallons**
Total	**100%**	**345.8752 Gallons**

4.4.2. Main Acid:

The main fluid in a sandstone acid treatment is the fluid used to remove the damage. It is typically a mixture of hydrofluoric (HF) and hydrochloric (HCl) or organic acids. HF acid is used because it is the only common, inexpensive mineral acid able to dissolve siliceous minerals. It is mixed with HCl or organic acid to keep the pH low when it spends to aid in prevention of detrimental precipitates. These mixtures are called mud acids because they were originally developed to treat siliceous drilling mud damage.

Table 4-3 Mainflush Concentrations

Fluid	Concentration	Volume
HCl-HF	9% HCl 1 %HF	342.10050039 Gallons of HCl 38.01116671 Gallons of HF
Corrosion Inhibitor	1%	38.01116671 Gallons
Mutual Solvent (EGMBE)	10%	380.1116671 Gallons
Clay Stabilizer (NH_4CL)	1%	38.01116671 Gallons
Iron Control Agent NTA (sequestering agent)	1%	38.01116671 Gallons
Surfactants (LOSURF-259)	0.8%	30.40893337 Gallons
Water	75.2%	2926.450903 Gallons
Total	100%	3801.116671 Gallons

4.4.3. Overflush (Postflush)

The overflush is an important part of a successful sandstone acid treatment. It performs the following functions:

- Displacement of the nonreacted mud acid into the formation.
- Displacement of the mud acid reaction products away from the wellbore
- . Removal of potential oil-wet relative permeability problems caused by some corrosion inhibitors.

The overflush fluid must be miscible with the acid in order to displace it. Therefore, aqueous base liquids should be considered as the first displacing and flushing fluid.

Table 4-4 Overflush Concentrations

Fluid	Concentration	Volume
HCl	7.5%	345.25266 Gallons
Clay Stabilizer (NH_4CL)	5%	230.16844 Gallons
Mutual Solvent (EGMBE)	10%	460.33688 Gallons
Water	93.5%	3567.61082 Gallons
Total	100%	4603.3688 Gallons

4.5. Matrix Acidizing Calculations

4.5.1 Data:

Table 4-5 Formation Data

Data	Value	
Well Name	Tawila 70	
Field	Tawila	
Well Type	Production	
Formation	Qishn S2 Classics	
Formation Thickness	37 ft	
UTM Coordinates	1 708 082.00 N 290 586.00 E	
Formation Length	5901-5949 (48ft)	
Perforations Depth	5920-5930	
Deviation Degree	Depth (ft)	Deviation deg.
	3135	2.75
	5452	2.50
	6652	1.50

Table 4-6 Reservoir Data

Data	Value	
Reservoir Pressure	953.5 psia	
Hydrostatic Pressure	2808.3 psia	
Productivity Index	2 STB/day/psi	
Drawdown Mobility	1300	
Tubing Diameter	5.5 inch	
Skin Factor	+2.7	
Porosity	Total	0.19
	Effective	0.13
	Secondary	0.06
Shale Volume	10%	
Water Saturation	16%	
Permeability	66 mD	
Matrix Density	2.71 gm/cc	
Temperature	169 F°	
Oil Formation Volume Factor	1.051	

Water Formation Volume Factor	1.0204
Oil Viscosity	2.44 cSt
Water Viscosity	0.391 cp
API	34

4.5.2. Acid Volume

$$Va = \frac{Vm}{X} + Vp + Vm \qquad (4.1)$$

$$Vm = \pi(r_a^2 - r_w^2)(1 - \emptyset)C_m \qquad (4.2)$$

$$Vp = \pi (r_a^2 - r_w^2) \emptyset \qquad (4.3)$$

$$\beta = C_a \frac{V_m MW_m}{V_a MW_a} \qquad (4.4)$$

$$X = \beta \frac{\rho_a}{\rho_m} \qquad (4.5)$$

Where:

Va = the required minimum acid volume, ft^3

Vm = the volume of minerals to be removed, ft^3

Vp = the initial pore volume, ft^3.

ra = the radius of acid treatment.

rw = the radius of the wellbore.

Cm = the mineral content, volume fraction.

$\emptyset$ = the porosity, fraction.

X = the volumetric dissolving power of acid solution, ft^3 mineral / ft^3 solution.

ρa = the density of acid, Ibm /ft^3.

ρm = the density of mineral, Ibm /ft^3.

β = the gravimetric dissolving power of acid solution, Ibm mineral/ Ibm solution.

Ca = the wright fraction of acid in the acid solution.

Vm = the stoichiometry number of minerals.

Va = the stoichiometry number of acid.

MWm = the molecular weight of mineral.

MWa = the molecular weight of acid.

Acid volume for the preflush zone:

-

$$Vm = \pi(r_a^2 - r_w^2)(1 - \emptyset)C_m$$

$$Vm = 3.14(3.401^2 - 0.401^2)(1 - 0.19)0.11$$

Vm=3.19 ft^3 of $CaCo_3$/ft of pay zone

$$Vp = \pi (r_a^2 - r_w^2) \emptyset$$

$$Vp = 3.14 (3.401^2 - 0.401^2) 0.19$$

Vp= 6.80 ft^3/ft of pay zone

$$\beta = C_a \frac{V_m MW_m}{V_a MW_a}$$

$$\beta = 0.075 \frac{1 * 100.087}{1 * 36.46}$$

$\beta =$ 0.206 Ibm $CaCo_3$/Ibm of 7.5 wt% of HCl solution

$$X=\beta \frac{\rho_a}{\rho_m}$$

$$X=0.206 \frac{72.44}{(169.2)}$$

X= 0.088 ft^3 $CaCo_3$/ft^3 wt% HCl

$$Va = \frac{Vm}{X} + Vp + Vm$$

$$Va = \frac{3.19}{0.088} + 6.80 + 3.19$$

Va =46.24 ft^3 7.5 wt% HCl solution/ft of pay zone

We multiple the value by 7.48 to change it to gallons:

Va =2.64*7.48

Va=345.8752 gallons 7.5 wt% HCl solution/ft of pay zone.

Acid volume for the main acid:

$$Vm = \pi(r_a^2 - r_w^2)(1 - \emptyset)C_m$$

$$Vm = 3.14(6.401^2 - 0.401^2)(1 - 0.19)*0.89$$

Vm = 92.38 ft^3 of SiO_2/ft of pay zone

$$Vp = \pi (r_a^2 - r_w^2) \emptyset$$

$$Vp = 3.14 (6.401^2 - 0.401^2) 0.19$$

Vp =24.35 ft^3/ft of pay zone

$$\beta = C_a \frac{V_m MW_m}{V_a MW_a}$$

$$\beta = 0.10 * \frac{2(80.08 + 100.087)}{2 * (36.46 + 20.01)}$$

$\beta =$ 0.32 Ibm SiO_2 & $CaCo_3$ /Ibm of 7.5 wt% of HCl-HF

$$X=\beta \frac{\rho_a}{\rho_m}$$

$$X=0.071 \frac{(72.44+61.152)}{(80.08+100.087)}$$

X=0.236 ft^3 SiO_2 & $CaCO_3$ /ft^3 wt% HCl-HF

$$Va = \frac{Vm}{X} + Vp + Vm$$

$$Va = \frac{92.38}{0.26} + 24.35 + 92.38$$

Va = 508.17 ft^3 1 wt% HCl-HF solution/ft of pay zone.

We multiple the value by 7.48 to change it to gallons:

Va = 508.17* 7.48

Va=3801.116671 gallons 1 wt% HCl-HF solution/ft of pay zone.

Acid Volume for the overflush:

$$Vm = \pi(r_a^2 - r_w^2)(1 - \emptyset)C_m$$

$$Vm = \pi(4.401^2 - 0.401^2)(1 - 0.19) * 1$$

Vm = 48.85 of 7.5 wt% of HCl /ft of pay zone

$$Vp = \pi (r_a^2 - r_w^2) \emptyset$$

$$Vp = 3.14(4.401^2 - 0.401^2)0.19$$

Vp = 11.46 ft^3/ft of pay zone

$$\beta = C_a \frac{V_m MW_m}{V_a MW_a}$$

$$\beta = 0.075 \frac{1 * (100.087)}{1 * 36.46}$$

$\beta = 0.206$ $CaCo_3$/Ibm of 7.5 wt% of HCl solution

$$X = \beta \frac{\rho_a}{\rho_m}$$

$$X = 0.206 \frac{72.44}{(169.2)}$$

$$X = 0.088$$

$$Va = \frac{Vm}{X} + Vp + Vm$$

$$Va = \frac{48.85}{0.088} + 11.46 + 48.85$$

$$Va = 615.42 \ ft^3$$

We multiple the value by 7.48 to change it to gallons:

$$Va = 615.42 \ ft^3 * 7.48$$

Va = 4603.3688 gallons 7.5 wt% HCl solution/ft of pay zone.

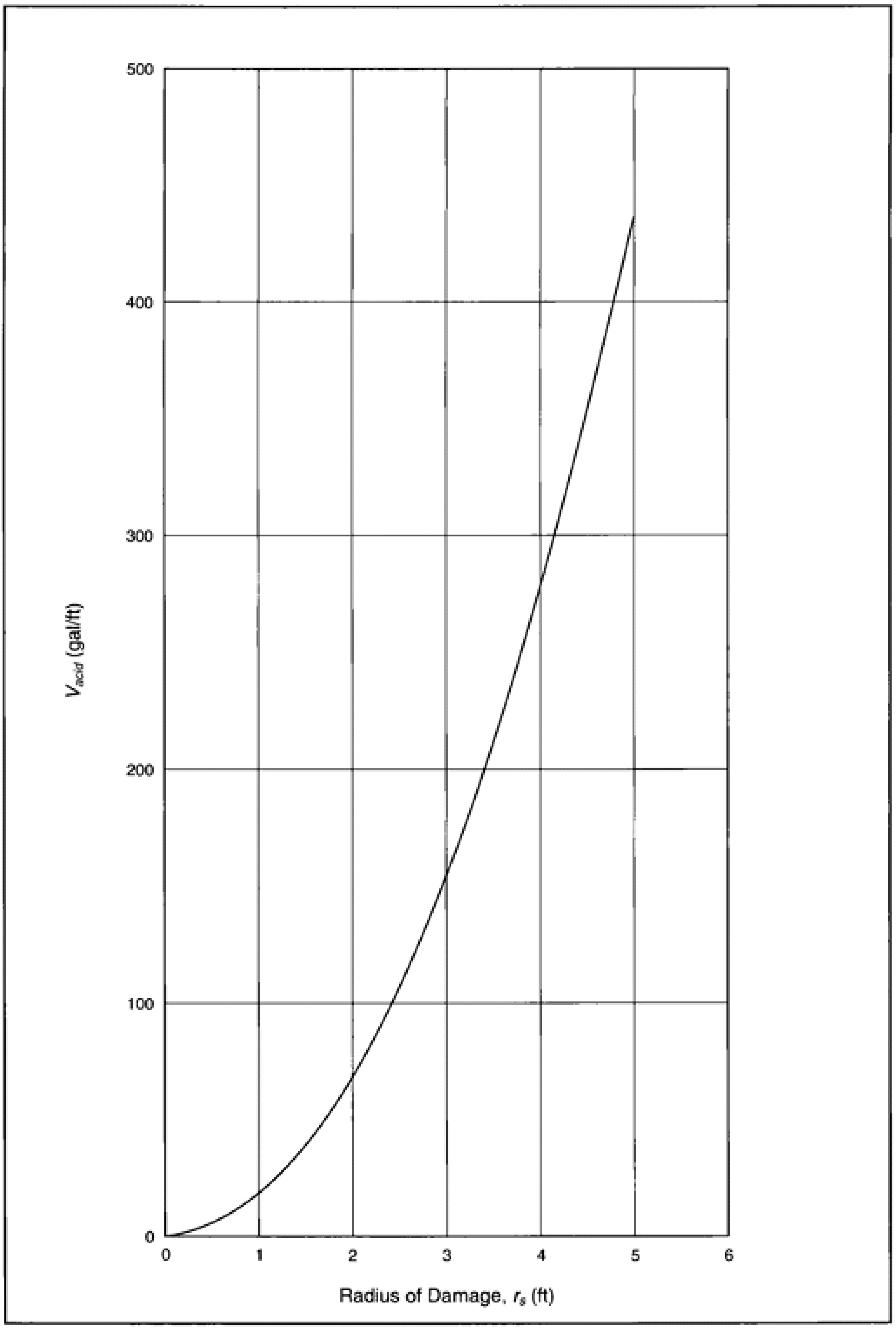


Figure 4-1 Radius of Damage Vs Acid Volume Relationship

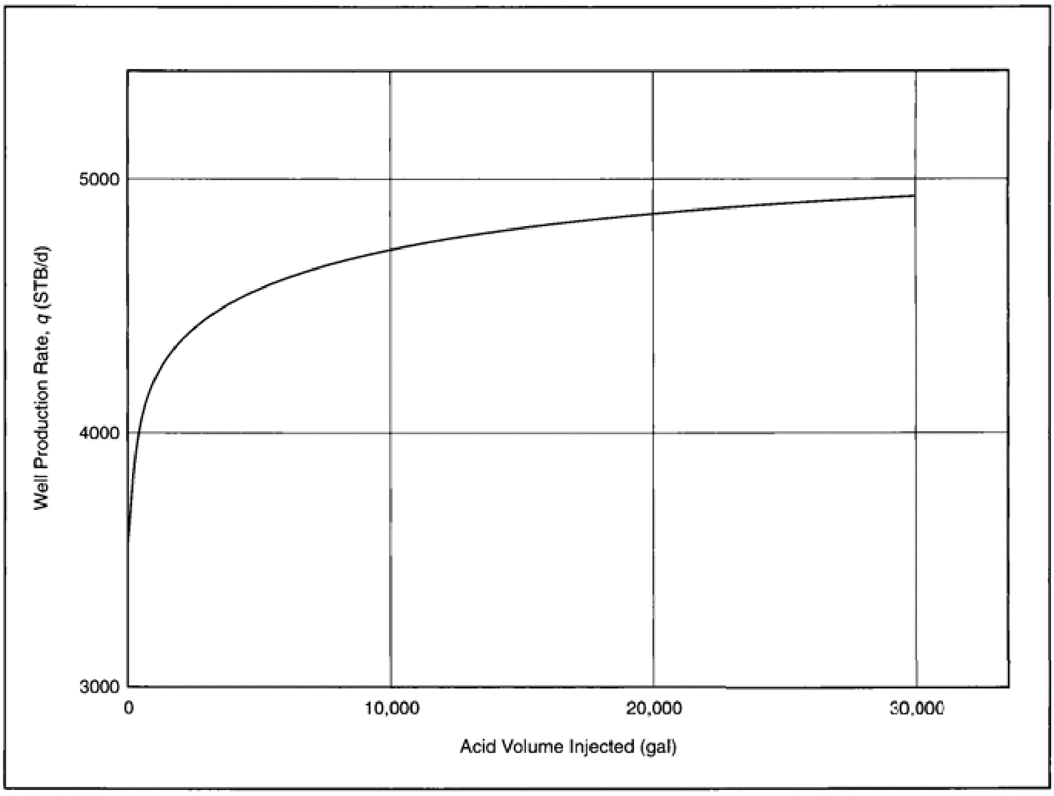


Figure 4-2 Production Rate Vs Acid Volume Relationship

4.5.3. Injection Rate and Injection Pressure

a) Injection rate

$$q_{I.max} = \frac{4.971*10^{-6}\,kh\,(P_{bd}-P_r-\Delta P_f)}{\mu_a(\ln\frac{\cdot 472\,r_e}{r_w}+s)} \tag{4.6}$$

$$\mathrm{P_{pd}} = \mathrm{G_f} * \mathrm{L} \tag{4.7}$$

Where:

qi, max = maximum injection rate, bbl/min.
k = permeability, mD.
h = thickness of the treated zone, ft.
Pbd = formation breakdown pressure, psia.
Pr = reservoir pressure, psia.
ΔPsf = safety margin, 200 to 500 psi.
μa = the viscosity of the acid solution, cp.
re = the drainage radius, ft.
rw = the wellbore radius.
S = skin factor.
Gf = formation fracture gradient, psi/ft.
L = total depth, ft.

$$\mathrm{P_{bd}} = 0.7 * 5923.5$$

$$\mathrm{P_{pd}} = 4146.45$$

$$q_{I.max} = \frac{4.971 * 10^{-6} * 66 * 11 * (4161.14 - 953.5 - 300)}{1.5(\ln\frac{\cdot 472 * 574.15}{0.401} + 2.7)}$$

$$q_{I.max} = 0.76\, bbl/min$$

b) Injection Pressure

$$P_{ing} = P_{wf} - \Delta P_h + \Delta P_f \quad (4.8)$$

$$\Delta P_h = .433\, \gamma\, L \quad (4.9)$$

$$\Delta P_f = \frac{518\rho^{0.79}\, q^{1.79}\, \mu^{0.207}\, L}{D^{4.79}} \mathrm{L} \quad (4.10)$$

$$P_{wf} = P_{pd} - \Delta P_f \quad (4.11)$$

Where:
Psi = surface injection pressure, psia.
Pwf = flowing bottom-hole pressure, psia.
ΔPh = hydrostatic pressure, psia.
ΔPf = fractional pressure drop, psia.
γ = specific gravity of acid.
q = injection rate, bbl/min.
μ = fluid viscosity, cp.
D = tubing diameter, in.
L = total depth, ft.

$$P_{wf} = 4161.45 - 300$$
$$P_{wf} = 3846.45\, psia$$

$$\Delta P_h = .433 * 1.08 * 5923.5$$

$$\Delta P_h = \ 2770.06\, psia$$

$$\Delta P_f = \frac{518(1.08)^{0.79} *(0.76\ )^{1.79} *(1.5)^{0.207}}{1000*2^{4.79}} 5923.5$$

$$\Delta P_f\ = 78.43\, psi$$

$$\Delta P_f\ = 158.65\, psi$$

$$P_{ing} = 3846.45\ - 2770.06\ + 78.43$$

$$P_{ing} = 1154.88\, psia$$

4.6. Post Treatment Evaluation

4.6.1. Flowback and cleanup techniques

Selection of the correct flowback procedure is critical. The fines loosened during the acid job are invariably produced back into the near-wellbore area. These fines can be removed in diluted concentrations that pass through the completion if small, gradual pressure drops are created.

The following are key factors to consider for flowback in sandstone formations:

- The fluids flowing back are more viscous than those injected. They are capable of carrying natural formation fines and other partially dissolved solids at lower velocities, which can cause plugging before the well cleans up completely.
- The spent acid usually has a higher density than the formation water. The coiled tubing pressure should be lower than when connate water is produced, owing to the higher hydrostatic pressure of the spent acid.
- Spent acid has an equilibrium established of potential precipitants, held in place by dissolved gases and dissolved salts. Should these gases (e.g., CO2) be removed from the spent fluid as a result of creating an excessive pressure drop, precipitation will occur.
- A minimum velocity is necessary for liquid to be voided from the tubing without slippage occurring.
- The majority of the additives that are injected are produced back. Because the acidizing additives are by design water soluble, they are partitioned into the water phase. This can cause separation and floatation equipment problems.

4.6.2. Effect of Acid Treatment

Since we cannot conduct a well test (build-up) to check the changes in the two main parameters (PI and S), a theoretical approach is applied to estimate the possible changes in the productivity.

- Using the Darcy's flow equation for both (pre-acidized well bore radius divided by acid radius), the following formula is established.

$$\frac{q}{q_a} = \frac{\ln\left(\frac{r_e}{r_w}\right) + S}{\ln\left(\frac{r_e}{r_{wa}}\right)}$$

Where:
$\boldsymbol{r_e}$ = is the drainage area radius, ft.
$\boldsymbol{r_w}$ = the wellbore radius, ft.
$\boldsymbol{r_{wa}}$ = acid invasion radius, ft.
$\boldsymbol{q}$ = Darcy's low for the wellbore radius .
$\mathbf{q_a}$ = Darcy's low for the acidized radius .

$$\frac{q}{q_a} = \frac{\ln\left(\frac{r_e}{r_w}\right) + S}{\ln\left(\frac{r_e}{r_{wa}}\right)}$$

$$\frac{q}{q_a} = \frac{\ln\left(\frac{574.15}{0.401}\right) + 2.7}{\ln\left(\frac{574.15}{13}\right)}$$

$\frac{q}{q_a} = 2.63$ is the anticipated production increase times to the pre-acidizing rate.

CHPTER FIVE

5. CONCLUSION, RECOMMENDATIONS, AND LIMITATIONS

5.1. Introduction:

In This study, the implementation of stimulation for Al-Tawila oil Field Block-14 by applying a matrix acidizing for one well (Tawila-70) was conducted and analyzed in chapter 4. The analysis done for one well (Tawila-70) was a result of many considerations regarding the formation characteristics, physical and chemical, with the acid mixture selection.

5.2. Conclusion:

In conclusion, matrix acidizing of sandstone formations is not an impossible task, but it is not simple either. Success requires a methodical, systematic, and analytic approach.

The following conclusions can be made for our study about sandstone matrix acidizing:

- We identified the damage, acid types, and other additives to use in our matrix acidizing treatment.
- We determined the knowledge of the chemical reactions involved among acids, formation minerals, and connate fluids. Also provided some guidelines for acid types, concentrations, and the sequence to prevent or reduce the precipitation of insoluble reaction products.
- We selected the appropriate types and volumes of preflush, main acid, and overflush which will help us prevent incompatibilities between formation fluids and acid system.
- We estimated the executed acid treatment and provided information to improve subsequent acid treatments in the same or similar formations.
- We were able to increase the productivity of the well.

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Specifically, sandstone matrix acidizing was applied on Tawila-70 which is a well located in the Tawila field Block-14. Moreover, the main acid of the treatment is a mixture of HCl-HF acids since the carbonate concentration is less than 20%. Furthermore, different types of additives were used with each mixture (preflush-main acid-overflush) for various purposes such as, preventing corrosion to equipment, control the precipitations of unwanted materials, prohibit the formation of unsolvable material, formation wettability…etc.

The surface injection pressure of the acid mix was 1154.88 psia, while the injection rate was calculated to be 0.76 bbl/min for three acid volumes of (345.9, 3801.12, and 4603.4 gallons) for the three stages (preflush, main acid, and overflush) respectively. To sum up, the anticipated production increase is 2.63 times to the pre-acidized rate.

5.3. Recommendations:

Below, we can find a summary, in order to shortly review on some operation recommendations before and after the treatment:

- During the preparation of the acid solution we should minimize open air time while mixing the fluid batches.
- Make sure the tanks and flowlines are clean.
- A corrosion inhibition measure is to not produce the spent acid into the flowline after the acidizing job, but in tank. We can never be sure that a 100% of the live acid totally reacted with the formation rock.
- Oxide layers which may develop on the surface metallic components should be removed by pickling in order to avoid downhole precipitations.
- Depending on the acid solution pumped, be aware that damage can also occur during shut-in time and not only during pumping reactions.

The quality and quantity of production we obtain as a result of the acid stimulation treatment is a unique response to the whole treatment of a well. All injected fluid stages, their sequence, their injection rate at each time step and the corresponding counter pressure of the formation result in one solution the productivity of the well as a direct result of the performance of the acid solution.

5.4. Limitations:

- Difficulties while conducting the calculations regarding the value of some variables that led to delay the time of finishing the study.
- Lack of some data that could have made the calculations and analysis easier and more accurate.
- The difficulty in conducting a well test (Build-Up) after the stimulation process to verify the success of the treatment.

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THE END