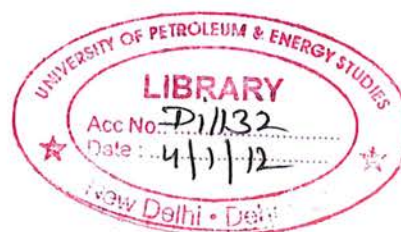# WELL STIMULATION USING ACIDIZATION TECHNIQUE

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May, 2010

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Well Stimulation Technique Using Acidization Technique

A thesis submitted in partial fulfilment of the requirements for the Degree
of

Bachelor of Technology

(Applied Petroleum Engineering, Upstream)

By

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Under the guidance of

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CERTIFICATE

This is to certify that Arpit Gupta & Namrata Bist, students of B.Tech (Applied Petroleum Engineering) have written their thesis on "Well Stimulation Using Acidization Technique" under my supervision and have successfully completed the project within stipulated time.

They have demonstrated high performance levels and dedication during the completion of their thesis.

Mr. Arun Chandel
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Acknowledgement

ABSTRACT

Matrix stimulation is a technique that is used to improve production from oil and gas wells and to improve injection into injection wells. Matrix stimulation is accomplished by injecting fluid (acid or solvent) to dissolve and/or disperse materials that impair well production in sandstones or to create new, unimpaired flow channels between a wellbore and reservoir in carbonate formations. In matrix stimulation, fluids are injected below the fracturing pressure of the formation.

Actually, the process is mainly used when the objective is to restore near well bore permeability after formation plugging during drilling, production, perforation, workover, completion, and sometimes due to wrong stimulation job.

Once it has been established that a well is producing below its potential, an assessment of the cause and location of the impairment must be made. Then the stimulation technique is determined. Selection of the stimulation technique is based on the productivity, lithology, operational limitations and various other considerations.

The treating fluid system is selected on the basis of field experience and laboratory testing and can be derived from an expert system.

A field validated stimulation simulator should be used for the systematic engineering of matrix stimulation treatments. A numerical simulator can be a valuable tool for predicting damage removal and evaluating skin effect evolution, flow profile and wellhead and bottomhole pressures versus injection rate for the proposed pumping schedule. The simulator should take into consideration both the chemistry and damage removal along with the placement strategy.

Objectives of well stimulation:

The deliverability of a damaged formation is not what actually is desired as per the calculations and simulators. Thus, this damage needs to be removed. Basically stimulation of a well aims to:

- Clean the hydrocarbon flow path which might have been plugged due to mud and other well control fluid.
- Form new conductive paths in the formation using specially designed fluids.
- Dissolve/disperse the clays which might otherwise swell and reduce porosity.
- Removal of the plugged fines.
- Also in tight reservoirs this technique is useful in increasing the permeability by forming widened flow channels. (Hydraulic Fracturing)
- In formations like carbonates, special acids are used to dissolve the formation resulting in modified porous channels (Vugs and Warmholes).

The above mentioned objectives need special treating equipments and fluids. Their proper amount and placement technique decides the success of the treatment program.

The main considerations done in this discussion is about the sandstone formation. The concepts are explained in details with the help of a case study also.

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FORMATION DAMAGE

1. INTRODUCTION

Formation damage is considered as any process that impairs the permeability of reservoir formations such that production or injection is decreased. Formation damage can be recognized by lower than expected productivity and accelerated production decline on affected wells. This is due to a reduced permeability in the near wellbore vicinity, which has been affected by the damage mechanism. This area of reduced permeability results in an additional pressure drop imposed on the producing system, which is proportional to the rate of production.

Formation damage can occur at any time during a well's history from the initial drilling and completion of a wellbore through the depletion of a reservoir by production. Operations such as drilling, completion, walkovers and stimulations, which expose the formation to a foreign fluid, may result in formation damage due to adverse wellbore fluid/formation fluid or wellbore fluid/formation reactions. While withdrawing fluids from a formation during normal production operations, formation damage may occur due to mechanisms such as fines migration or scaling which results from imposing of pressure drop on the formation and the formation fluids.

If formation damage is suspected to be the cause of a well's low productivity, there are many techniques available to evaluate a well in order to identify this problem. Once the presence of formation damage is concerned, additional measures can be taken to assure that a stimulation attempt has a good probability of success.
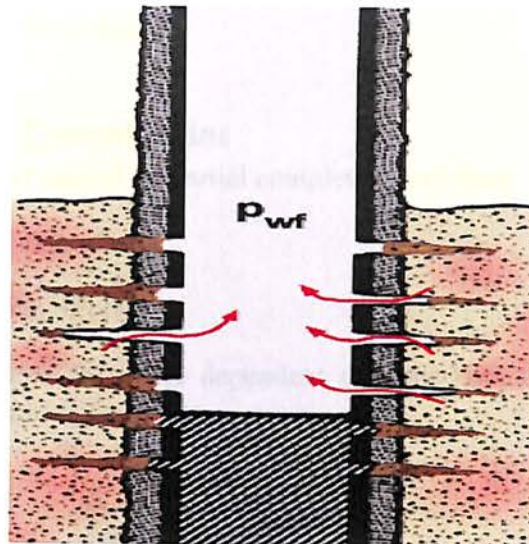
Fig.1 formation damage

1.1 FUNDAMENTALS OF SKIN

Skin is the zone around the wellbore of altered permeability. If the pedrmeability of the skin is less than the reservoir permeability, the well is damaged. Conversely, if skin permeability is more than reservoir permeability, the well is stimulated.

Skin effect by partial completion and slant

The skin effect resulting from the partial penetration length may be unavoidable because it typically results from other operational considerations (such as the prevention of gas coning). A deviated well, without damage, should have a negative skin effect. Thus , a small skin effect or even one equal to zero obtained from a well test in a highly deviated well may mean considerable damage. Removal of this damage with appropriate stimulation could increase the deviated well production (or injection) considerably.

Perforation skin effect

Skin effect caused by perforation. This skin effect is a composite involving the plane flow effect S_H, vertical converging effect S_V and well bore effect S_{wb}.

$$S_p = S_H + S_v + S_{wb}$$

Damaged skin effect

For damaged wells IPR curves and flow efficiencies are useful to calculate the maximum rate possible from a damaged well and additional recovery if stimulation is carried out.

The total skin effect may be written as:

$$S_t = S_{C+\Theta} + S_P + S_d + \sum \text{pseudoskins}$$

Where $S_{C+\Theta}$ is skin effect caused by partial completion and slant.

S_p is perforation skin effect

S_d is damaged skin effect

And pseudo skin factors are phase dependent and rate dependent effects that could be altered by hydraulic fracturing treatments.
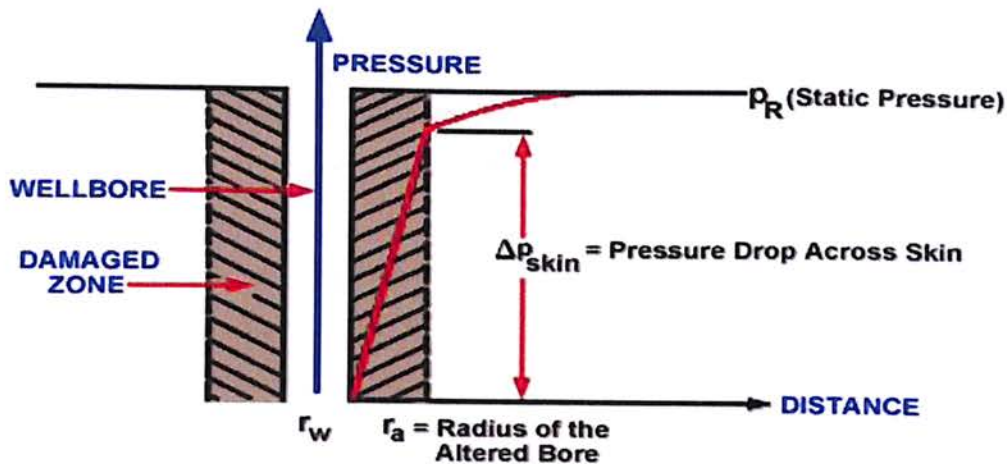
Fig.2 Pressure drop across skin

1.2 R0CK COMPOSITION AND MINERALOGY

Types of minerals

1. **Detrital minerals** – these are minerals which survive weathering and transportation. e.g. Quartz, orthoclase, microcline, plagioclase.

2. **Secondary minerals** – these are the minerals formed during weathering and transportation. E.g. clay minerals

3. **Precipitated minerals** – these are minerals formed directly from solutions because of chemical or biochemical reactions. E.g. calcite and argonite.

4. **Authigenic minerals** – these are minerals formed in sediments during and after depositional process. E.g. dolomite.

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Types of rocks

1. Sandstone – these are composed mainly of sand grains, cemented by silica or calcium carbonate. The sediments are often more than 98% SiO_2. In some sandstone, both detrital quartz and detrital feldspars are present along with significant amounts of Al_2O_3, K_2O, Na_2O, and CaO.

2. Limestone – they are composed mainly of carbonate, which are extraction of calcium and precipitation of $CaCO_3$.

The limestone can be mainly subdivided as follows:

- Lithographic limestone - they are formed from carbonate mud.

- Fossiliferous limestone - it is composed of fossil fragments cemented by coarsely crystalline calcite.

- Dolitic limestone – these are cemented, inorganic or bio chemical rounded mass.

- Shale - major minerals of shale are clay minerals and quartz. They contain some organic matter also.

1.3 Clays

There are 2 basic structural units involved in the atomic lattice of most clay minerals.

1. **Silica tetrahedral sheet** – in each tetrahedron a silicon atom is equidistant from 4 oxygens or hydroxyls. The silica tetrahedral groups arranged to form a hexagonal network which is repeated infinitely to form a sheet of composition $Si4O6(OH)4$. The tetrahedras are arranged so that all their tips point in the same direction and all their bases are in the same plane.

2. **Alumina octrahedral sheet** – in this sheet aluminium, iron or magnesium atoms are embedded in octahedral coordination, so that they are equidistant from six oxygens or hydroxyls. When aluminium is present only two thirds of the possible positions are filled to balance the structure gibbsite, having formula $Al_2(OH)_6$ and when Mg is present, all the positions are filled to balance the structure brucite, having formula $Mg_3(OH)_6$.

Types of clay

I) **Kaolinite** – it is 1:1 clay, that is one tetrahedral sheet combined with one octahedral sheet. The silicon tetrahedral and aluminium octahedral sheets are linked by shared oxygens, whereas the lower surface of the octahedral sheet is composed of hydroxylious. Since the alumina and silica sheets are covalently bonded, as they share the same oxygen atoms, the different forces such as hydrodynamic, capillary, electrical, salvation will not be sufficient to separate the two sheets forming a single layer. Kaolinite particles that occur naturally are composed of many layers stacked one on top of the other and the binding forces are hydrogen bonds supplemented by van der waal's forces. The strength of this binding is sufficient to prevent water penetration between the layers, when kaolinite is immersed in water, therefore it is known as non swelling clay. So, the chance of formation damage due to swelling due to presence of kaolinite is negligible, but it is also referred as migrational fines problem clay and can cause formation damage by fine migration.

II) **Montmorillonites** – it is 2:1 clay and is composed of layers consisting of two silica tetrahedral sheets surrounding of central alumina octahedral sheet and are covalently bonded. In the stacking of silica alumina silica sheets, the oxygen layer of each unit are adjacent corresponding oxygen layers of the neighboring units resulting in a very weak bond and an excellent cleavage between them. Therefore, the water and other polar molecules can enter between the unit layers causing the lattice to expand and resulting in swelling. The thickness of the liquid film increases the dipole moment of the reacting fluid increases. Therefore, montmorillonites can cause formation damage due to clay swelling and clogging of pore throats by deflocculated clays.

III) **Illite** – the basic structure of illite minerals is similar to montmorillonite, each layer being composed of two silica tetrahedral sheets with a central octrahedral sheet. The unit is same as that for montmorillonite, except some of the silicon is always displaced by aluminum's and the resultant charge deficiency is balanced by potassium ions positioned between the layers. Depending upon the degree to which aluminium has been substituted for silicon and other cations perhaps sodium has replaced potassium – illites, may act like montmorillonites and can show swelling property with water. But, normally it is also referred as migrational fines problem clay, as it acts as a fish net to catch the moving formation fines to create the permeability blocks.

IV) **Chlorite** – chlorites generally consist of alternate kaolinite like and brucite like layers and there is considerable substitution within the structure. The bonding between layers is partly electrostatic in nature due to substitution and partly due to interaction between adjacent oxygen and hydroxyls. This latter hydrogen bonding mechanism is similar to that found in kaolinite. The main problem this clay presents is that it has

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often high iron content, so acids and other treatment chemicals should be treated with iron – chelating agents to prevent iron precipitation.

- **Surface charge of clays**

There are 3 different mechanisms responsible for the existence of fixed surface charge on the clays. These are:

1) **Due to substitution** – during formation of clay minerals, the wrong ion may be incorporated into the lattice sites, and later substitution of ions, the charge is developed, which remains fixed and cannot be altered. The substitution of aluminium ion Al^{+3} for Si^{+4} intotetrahedral silicon lattice can take place and it may leave on excess negative charge.

2) **Due to broken bonds** – surface charge may also be developed as a result of broken bonds at the edges of the clay crystals or of dislocations along the crystal faces.

3) **Due to hydroxylation of mineral oxides and silicates** – mineral oxides and silicons tend to be hydroxylated in water at the exposed surface of the mineral. The reaction between metal ion which is positively charged and oxide ion which is negatively charged takes place in presence of water and in turn receive or donate a proton depending on the pH of the water.

Electrical double layer

The electrical double layer consists of a highly localized charge (surface charge) and a diffuse charge. As, the surfaces of minerals are charged, so to neutralize it, the ions of opposite sign gather in the aqueous solution near the charge surface. These ions are not drawn immediately adjacent to the surface because of thermal fluctuations and they remain in a thin layer surrounding the mineral surface with increasing concentration as the distance from the surface decreases. The diffuse region contains more positive ions, than negative ions due to attraction of the negatively charged surface.

Cation or Base Exchange

The process of exchanging ions present in diffuse layer is known as ion exchange. If electrolyte composition of the bulk water phase is changed, for example, replacing a NaCl solution with CaCl2 solution, then Na+ ions initially present in diffuse layers will be replaced by Ca2+ ions, as the cations in the diffuse layer are the same ones that exists in the bulk water immediately adjacent to the surface. The exchange of ions takes place in such fashion so as to maintain electrical neutrality.

- **Cation exchange capacity**

This process is used to prevent the chances of clay dispersion by exchanging the Na^+ ions by Ca^{2+} ions.

- **Formation water**

Formation water generally contains dissolved salts especially sodium and calcium chlorides. The property of formation water is not fixed and is dependent upon composition of water during sedimentation, rock water interaction and interaction with infiltering water.

- **Clay and particle damage**

Mainly the damage due to clay and other particles may be divided into 3 groups:

1)   Fines migration
2)   Clay swelling
3)   Induced particle plugging

- **Fines migration:**

Movement of detached particles along with produced fluid in the porous reservoir. The particles can bridge across the pore throats in the near wellbore region causing formation damage and reduce the well's productivity. When the damaging particles come from the reservoir rock, they are usually referred to as fines.

Importance of fines migration

Clay may also act as a cement, holding the matrix grains together. As a binder or cement, clay may also react with fluids such as acid and water to disaggregate the formation. If the clay cement is shielded by a quartz overgrowth, as in common in many types of sandstone, the clay will not be reactive. Only authigenic clays, unprotected clay cements and a few detrital clays on the pore boundary are worth consideration as potential damage mechanisms.

A.-"Discrete particle" kaolinite **B.-"Pore-lining" chlorite** **C.-"Pore-bridging" illite**
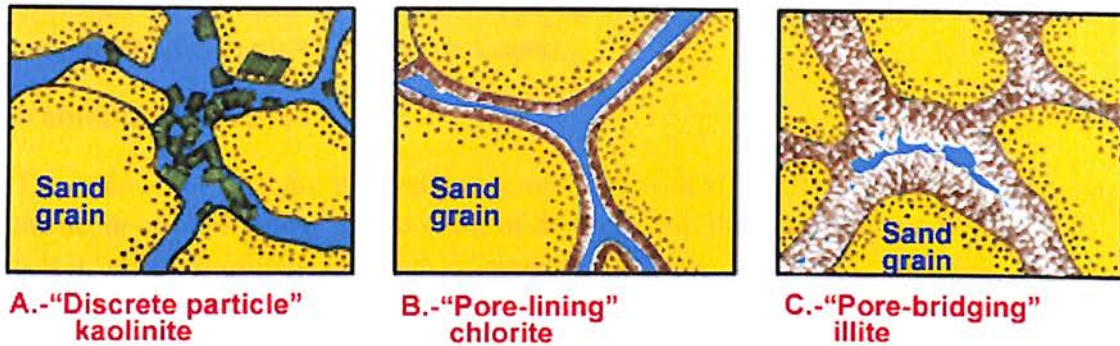
(from Neasham, 1977; by permission of SPE)

Fig.3 Fines migration

Remedial measures

To control clay migration, it is recommended to keep the:

1) Formation clays from swelling by using inhibitive systems (i.e., brine fluids)
2) pH in the 8.3 to 9.0 range
3) flow rates low when initiating or resuming production

- **Swelling clays**

Clays may change volume as the salinity of the fluid flowing through the formation changes. The most common swelling clays are smectite and smectite mixtures.

Importance of clay swelling

Several experiences are available of clay swelling in sandstones, showing ion exchange, movement or critical salt concentration triggering clay. Changes in formation permeability resulting from the alteration of clay are due to the amount, location and type of clay minerals within the formation. The total quantity of clay inside the formation is a misleading indication of potential changes to permeability. It is the arrangement of the clay, its chemical state at the moment of contact and the location of the clay with respect to the flowing fluids that are responsible for the changes. Predicting the response of the clay to water flow is almost impossible without testing. Clays or other solids from drilling, completion or work over fluids can invade the formation when these particles are smaller than the pore throat

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openings. Any subsequent increase in flow rate through the invaded zone will force a high concentration of particles into the rock matrix.

Remedial measures

The removal of smectite is usually accomplished with HF or floroboric acid, depending on the depth of penetration. In the event of deep clay swelling problems (more than 2 ft) , the best treatment is usually a fracture to bypass the damage.

• Induced particle plugging

In addition to naturally occurring migrating particles such as clays and fines, many foreign particles are introduced into the formation during normal well operations. Drilling, completion, work over, stimulation, and secondary or tertiary production operations can cause the injection of extraneous particles into the formation. These foreign or external particles may plug the pore spaces which creates obstruction to the fluid flow and thereby decreases the productivity or injectivity.

Importance of particle plugging

Particle damage from injected fluids happens in the near wellbore area plugging formation pore throats. Problems include bridging of the pores, packing of perforations and the loss of large amounts of high solids fluid into natural fractures or propped fracture systems. Particulate materials in drilling fluids that are potentially damaging are clays, cuttings, weighting agents and loss control materials including polymers. These materials can be a problem independent of mud type. Workover and stimulation fluids can also contain suspended solids including bacteria and polymer residues. Particles in stimulation fluids are a result of poor water quality, tank coatings, tank residuals, and piping and tubing debris. The problem with stimulation fluids is that they can contain effective cleaners and acids that disperse and partially dissolve the debris inside of the tanks and piping's on their way to the formation. Acid treatments may also cause formation damage because of the precipitation of secondary acid reaction products. Precipitation products include iron hydroxide, calcium fluoride, potassium flurosilicate and silica. Gelatinous precipitate such as ferric hydroxide can completely plug pores and can be particularly difficult to remove.

Remedial measures

The generation of the induced particle plugging should be avoided as much as possible by using treated and clear fluid, which is to be injected in the formation. In case the formation is damaged by the induced particle, then study should be carried out to find out the nature of the particle which has plugged the formation pores and accordingly proper treating fluid should be injected which can dissolve those particles.

1.4 Damage due to Organic deposition

Parrafin and asphaltene deposition in the formation and around the well bore creates a barrier for the transportation of the crude oil to the tubing. Organic damage may occur naturally or through various intervention practices used in the oil fields. The primary mechanism for paraffin deposition is thermal cooling. Decrease in temperature promotes paraffin deposition. The key mechanisms for asphaltene deposition are the decrease in pressure and the introduction of incompatible fluids.

Mechanisms:

1) **Solubility effect** – deposition of heavy organics can be explained by an upset in the polydisperse balance of oil composition. Any change in temperature, pressure or composition may destabilize the polydisperse oil. Then the heavy and polar fractions may separate from the oil mixture into steric colloids, micelles, and another liquid phase or into a solid precipitate. Segments of the seperated fractions which contain sulphur, nitrogen, and hydrogen bonds could start to flocculate and as a result produce the irreversible heavy organic deposits which may be insoluble in solvents.

2) **Colloidal effect** – some of the heavy organics will separate from the oil phase into an aggregate and then will remain suspended in oil by some peptizing agents, like resins, which will be adsorbed on their surface. The amount of peptizing agent adsorbed is a function of its concentration in the oil. Migration of peptizing molecules from the surface of heavy organic particles could take place due to the change in their chemical potential balance between the bulk oil phase and the surface phase.

3) **Aggregation effect** – the peptizing agent concentration in oil may drop to a point at which its adsorbed amount would not be high enough to cover the entire surface of heavy organic particles. This causes the potential for aggregation of heavy oganic particles due to development of free active sites on their surfaces, and their eventual flocculation.

4) **Electro-kinetic effect** – when a crude oil is flowing in a conduit, there is an additional effect to be considered in the behaviour of its heavy organic constituents. This is because of the development of electrical potential difference along the conduit due to the motion of charge particles. This electrical potential difference could then cause a change in charges of the colloidal particles further down in the pipe, the ultimate result of which is their untimely deposition and plugging of the conduit. The factors influencing this effect are the electrical and thermal charateristics of the conduit, flow regime, flowing oil properties, characteristics of the polar heavy organics and colloidal particles.

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Variation of pressure:

Variation of pressure exerted on a petroleum fluid can cause the deposition of some of its heavy organic contents. As the crude flows up in the well it's pressure decreases, which may cause gas phase separation and as a result the heavy organics deposition.

Field problems:

Precipitation of asphaltenes can cause formation plugging and wettability alterations which can lead to reduced recovery efficiencies. In many cases, the precipitated asphaltenes can plug up the well tubing or can be carried to the well head, through the flow lines and into the separator and other downnstream equipment causing expensive problems. The place where the asphaltene problem is most acute is perhaps in the well bores and well tubing. Asphaltene deposition inside the well not only can plug the well and result in production losses, but also can cause damage to downhole equipment .

Requirements for asphaltene control:

1) Initially laboratory work may be necessary to quantify and characteristize the various families of heavy organics present in a crude and in general shed light on the reasons for such depositions. Laboratory work joined with statistical mechanical modelling may result in the construction of heavyorganics deposition envelop (HODE) such as a graph which would indicate the ranges of temperature and pressure where the crude deposits out heavy organic compounds at various temperature, pressure, compositions/blending, and electro kinetic Effects and flow conditions.

2) To combat the heavy organics deposit formation the completing wells with a dual completion is necessary. This is with the purpose of:

   a) Using the second tubing string for solvent or dispersant injection or circulation

   b) Access for lowering production testing production testing devices. Sometimes the second tubing string is used for production to meet production targets when the main string is shut-in for maintenance or heavy organics cleaning.

3) Static and dynamic compatibility modeling using the advanced statistical and fluid dynamic techniques can be quite efficient and economical for shedding light on the problem by constructing heavy organics deposition envelopes (HODE).

4) The decision to produce first the top zone of the reservoir, which is generally less prone to heavy organics deposition, is always preferred. Actually most of the producing wells must be completed dual commingled. Production surveys would show from which zone most of the oil was being produced.

5) In certain circumstances mechanical removal techniques may be effective means of combating the heavy organics problems.

6) Solvent treatment of the oil is considered to be beneficial in some cases because it dilutes the crude oil and reduces the tendency of the heavy organics to precipitate.

7) Circulation with hot oil may be used to avoid or reduce the heavy organics deposition problem.

8) Injection of dispersant or antifoulants may be effective in certain crude oils where the ratio of resin to asphaltenes is not high enough to prevent asphaltene flocculation and as a result heavy organics deposition.

1.5 Damage due to Emulsion

A crude oil emulsion is a dispersion of water droplets in oil. Produced oil-field emulsions can be classified into 3 broad groups.

1) Water-in-oil
2) Oil-in-water
3) Multiple or complex emulsions

Emulsions have to be treated to remove the dispersed water and associated inorganic salts in order to meet crude specifications for transportation, storage and export and to reduce corrosion and catalytic poisoning in downstream processing facilities.

Oilfield emulsions are characterized by a number of properties including appearance, basic sediment and water, droplet size, bulk and interfacial viscosities, conductivities etc. Some of these properties are:

1) Drop size and drop size distribution: droplet size distribution in an emulsion determines the stability of the emulsion and should be taken into consideration in the selection of optimum treatment protocols. The smaller the size of the dispersed water droplets, the longer the residence time required and larger separating plant equipment sizes.

2) Viscosity of emulsions: can be substantially higher than the viscosity of either water or oil. It depends on a number of factors such as the viscosities of water and oil, volume fraction of water dispersed, droplet size distribution, temperature, shear rate, amount of solids present.

3) Interfacial films: oilfield emulsions are stabilized by films that form around water droplets at the oil water interface. These films enhance the stability of emulsions by reducing interfacial tension and increasing the interfacial viscosity. Highly viscous interfacial films retard the rate of oil film drainage during the coagulation of the water droplets by providing a mechanical barrier to coalescence. This can lead to reduction in the emulsion breakdown.

Stability of emulsions has been correlated with the mobility of interfacial films. Surfactants that modify the rigidity of the film can considerably speed up the demulsification process.

Factors affecting stability:

1) Heavy polar fraction in crude oil – emulsifiers are concentrated in the higher boiling, polar fraction of the crude oil. These include asphaltenes, resins, and oil soluble organic acids and bases. These compounds are the main constituents of the interfacial films surrounding the water droplets that give the emulsions their stability. Asphaltenes have surface active properties that make them good emulsifiers. They hang at the oil water interface. The accumulation of asphaltenes at the interface results in the formation of the rigid film.

2) Solids – fine solid particles present in the crude oil are capable of effectively stabilizing emulsions. Solid particles stabilize emulsions by diffusing to the oil water interface where they form rigid structures that can inhibit the coalescence of emulsion droplets.

3) Temperature - temperature effects the physical properties of oil, water, interfacial films, and surfactant solubility's in the oil and water phases. These in turn affect the stability of the emulsion. The most important effect of temperature is on the viscosity of emulsions.

4) Droplet size – the droplet size distribution effects emulsion viscosity, it is higher when droplets are smaller. Emulsion viscosity will also be higher when the droplet size distribution is narrow i.e. droplet size is fairly constant. Emulsions that have smaller droplet size will be more stable.

5) pH – the stabilizing, rigid emulsion film contains organic acids and bases, asphaltenes with ionizable groups, and solids. Acids or low pH generally produces water in oil emulsions whereas basic or high pH produces oil in water emulsions. The pH of the water affects the rigidity of the interfacial films.

6) In situ emulsion phenomenon – emulsification is believed to be initiated b y the presence of natural emulsifying agents which are present in the oil. These agents are slightly soluble in the oil phase and are attracted to the water phase causing reductions in interface tension between the water and the oil. This results in a film in forming about the dispersed water particle causing the particle to remain isolated and inhibits coalescence into larger particles which would more readily separate and destabilize the emulsion.

Demulsification:
Demulsification is the breaking of a crude oil emulsion into oil and water phases. Two aspects of demulsification are of importance
   a) The rate or the speed at which this separation takes place
   b) The amount of water left in the crude oil after separation.

The factors that enhance or speed up the emulsion breaking include:
   1) Increase in temperature.
   2) Reducing agitation or shear.
   3) Increasing residence or retention time.
   4) Solids removal.
   5) Control of emulsifying agents.

Mechanisms involved in demulsification:

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It is a 2 step process

1) **Flocculation or aggregation:** during flocculation the droplets clump together forming aggregates or floccs. The rate of flocculation depends on a number of factors including water cut, temperature, viscosity of the oil, and the density difference between oil and water.

2) **Coalescence** – during coalescence water droplets fuse together to form a large drop. This is an irreversible process that leads to a decrease in the number of water droplets and eventually to complete demulsification.

Demulsification methods:

1) Chemical methods – is adding chemicals called demulsifiers.
2) Thermal methods – heating the emulsion enhances its breaking or separation. It reduces the viscosity of the oil and increases the water settling rates.
3) Mechanical methods - There is a wide variety of mechanical equipment available in breaking of oil field produced emulsions. These include free water knock out drums, two and three phase separators, desalters and settling tanks.
4) Electrical methods – high voltage electricity is often an effective means of breaking emulsions.

1.6 Scale Deposition

Scale is a solid mineral deposit usually formed from produced salt water. Because water constantly dissolves and a deposits solid, scale is an endless problem in the petroleum industry. Scale occurs in primary production wells, secondary wells, injection wells, disposal wells, and pipelines that connect wells to tank batteries.

Scale can be caused by several factors:
Pressure change
Temperature change
Impurities
Additives
Changes in pH
Variation of flow rates
Fluid expansion
Gas expansion
Mixing of incompatible waters

The effect these scales have on well depends largely on their location and the amount deposited in the system. Scales can restrict and completely choke production in the tubing, in

the flow lines, at the sand phase, or in the perforations. Scales can deposit in fractures and formations that are distant from the well bore.

Scale types:
1) Water soluble – NaCl
2) Acid soluble – $CaCO_3$, $FeCO_3$, FeS, Fe_3O_4, Fe_2O_3, $Mg(OH)_2$
3) Acid insoluble – $CaSO_4.2H_2O$, $CaSO_4$, $BaSO_4$, $SrSO_4$, $BaSr(S_4O)_2$

Characteristics of scales:

Calcium Carbonate:
The causes of formation calcium carbonate scale in well tubular or in wellbore are changes of pressure and temperature, increase of pH (such as the loss of CO_2), increase of calcium concentration, increase of carbonate etc.

Calcium sulfate:
The solubility of calcium sulfate ($CaSO_4$) or gypsum, increases from ambient to 92^0 F and then decrease at higher temperatures. Formation water becomes saturates in calcium sulfate at bottomhole conditions. As the fluid is produced, its temperature and pressure decreases , and gypsum precipitates in the wellbore or wellhead.

Barium sulfate:
Factors for barium sulfate precipitation include lower temperatures, dilution of brine content, dilution of carbonate content, mixing of incompatible water etc.
The only way to remove precipitated barium sulfate is by mechanical scraping or reaming which is costly.

Chemical scale inhibitors control the deposition of scale by either interacting with the microscopic scale surface or altering the crystal structure as it is formed or by sequestering the ions that precipitate as a scale.

Chelation:
This method chelates the ion that is causing scale, which requires one part inhibitor for each part potential scale.

Threshold inhibition:
In this method the binding site of the scale inhibitor molecule is attracted to the charges on the small scale crystal. Because the inhibitor is attached to the scale crystal, the crystal grows no larger. Eventually the crystal re-dissolves and releases the inhibitor to repeat the process.

Scale inhibitors:

The type of scale inhibitors normally used in oil fields are:
1) Polyphosphate and phosphate esters
2) Slowly soluble polyphosphates
3) Phosphonates

4) Polyacrylic acid and other carboxylic acid containing polymers.

Treatment methods:
- Placing during a stimulation treatment
- Squeeze treatments/chemical placement techniques (CPT)
- Continuous injections

Placement during stimulation treatment:
During a stimulation treatment, scale inhibitors are placed in one or two methods: liquid inhibitor is placed in the prepad or solid inhibitor is placed with the proppant laden fluid. Liquid scale inhibitors are placed ahead of the fracturing fluid because they can interfere with cross linked fluid. Because solid inhibitors are soluble in acid, the fractured well should not be acidized until the inhibitor ceases to provide protection.

Squeeze treatment:
It involves pumping the liquid scale inhibitor down a well string and forcing it into the formation. This technique enables the inhibitors to be adsorbed on or bound to the high surface area of the formation. The scale inhibitor slowly releases as the produced fluids from the well flow across the treated area into the well bore.

Chemical placement techniques (CPT)
CPT is a method of placing liquid inhibitor into a fractured formation to achieve slow feedback and long term control of scale. CPT is also a squeeze treatment on a naturally or hydraulically fractured well. This technique must be used in natural or induced fractures or in conjunction with a fracturing treatment because of the pressure drop profile of a fractured formation is required.

1.7 Damage due to Bacteria

Bacteria normally can grow in many different environments and conditions:
Temperatures ranging from 12°F to greater than 250°F, pH value ranging from 1 to 11 salinity are 30% and pressures to 25000 psi.
The bacteria most troublesome in the oilfield are sulfate-reducing bacteria (SRB), slime formers, iron-oxidizing bacteria and bacteria that attack polymers in fracturing fluids and secondary recovery fluids. SRB causes the most problems in a reservoir.SRB reduces the sulfate or sulfite in the water to sulfide and produce hydrogen sulfide (H_2S) as a byproduct.

Effect of temperature on bacteria growth:
Temperature is one of the major controls on the growth of the bacteria and their by products. At different temperatures the bacterial growth process varies. At 30°C generally complex biofilm with minor hydrogen sulfide (7 ppm) is generated. At 60°C complex biofilm gets replaced by a single population of small coccoid cells, which coat the quartz cement overgrowths. The liberation of H_2S gas is therefore only likely to occur in any areas of the

reservoir at a temperature lower than 60°C i.e., along a thermal cooling front close to a continuous seawater injection well.

Mineral bacterial interaction:
The type of mineral present has a significant effect of plugging characteristics of the rock formation due to bacteria. They have affinity towards negative charge towards any particular mineral and their subsequent accumulation around that mineral in pore space.

Method of controlling bacteria:
Bactericides are used commonly to control the bacteria. The iron oxidizing bacteria produce some corrosion, but they usually cover SRB colonies and protect them from attack.

1.8 Water Block

Loss of aqueous fluids during drilling, completions and workover operations causes a ring of high water saturation around the wellbore. This can potentially reduce the gas flow into the well; this is called "water blocking".

Problem:
Lower permeability reservoirs will have more significant water block problems. This is due to smaller volumes of gas flow, leading to longer times for the water block to clean up.

Clean up of water block:
This occurs as gas flows past this high liquid saturated region and removes liquid by displacement and mass transfer.
Treatment;
Removal of water from gas wells has often been handled with acid and alcohol solutions or acid and mutual solvent solutions. These systems attempt to reduce the surface tension of the injected water which is trapped in the pores of the rock.
The damaged condition usually occurs when:
1) The pore throats are very small
2) The injected water in the pores of the rock was untreated
3) The bottomhole pressure is low

1.9 Formation Damage during various Well operations

1.9.1 Formation damage during drilling:

Formation damage during drilling activities can be characterized by mainly two processes:

- Invasion of mud solids
- Invasion of mud filtrate

Invasion of mud solids:
Invasion of drilling fluid solids is favoured by high drilling fluid density causing large overbalance pressure, large pore size of the formation rock, presence of fissures and natural fractures, small particle size in the drilling mud, low drilling rate resulting in mud cake destruction and long formation to mud contact time, high drilling fluid circulation rate, contact time during bit trips etc.

Invasion of drilling fluid filtrate:
Factors that increase the probability of drilling filtrate invasion usually include, high overbalance and long formation-to-drilling-fluid contact time.

Mechanisms of reducing well productivity by mud solids or filtrate are:
1. Water block.
2. Swelling and dispersion of indigenous reservoir clays.
3. Plugging of its formation pore throats by solid particles.
4. Polymer invasion.
5. Mutual precipitation of soluble salts in the filtrate and formation water
6. Slumping of unconsolidated sands.

1.9.2 Formation damage during cementing:
The different damage mechanisms in cementing operations are as follows:-
1. Fines migration from the cement slurry into the formation.
2. Precipitation of solids from the cement within the formation.
3. Differential dissolution of reservoir minerals leading to fines migration.
4. Precipitation of expansive secondary minerals following reservoir mineral dissolution.

1.9.3 Formation damage during completion & workover operations:
The different mechanisms are as follows:
1. Hydration and swelling of clay minerals.
2. Movement and plugging by clay size particles in the formation.
3. Plugging by invading materials from the wellbore fluids.
4. Emulsions and water blocks due to lost wellbore fluids.
5. Relative permeability effects.

6. Precipitation of scales.
7. Plugged perforations due to improper perforating conditions.

1.9.4 Formation damage due to sand control:
Major sources of damage in gravel packs are:
1. Improper placement of the gravel pack, allowing perforation filling by formation sand
2. Damage by unbroken gels or formation particles.
3. Invasion of loss control materials.
4. Thread dope, paint, rust and polymer residues forced between formation sand and the gravel pack during displacement.
5. Inadequate gravel size, leading to gravel pack invasion by formation fines during production.
6. Screens with slots too large or with slots too narrow that become plugged and reduce production.

1.9.5 Formation damage during production:

The following are responsible for damage during production

1. Fines migration
2. Scale deposition
3. Paraffin, wax, Asphaltene formation
4. Wettability alteration
5. Water block
6. Condensate banking
7. Gas breakout
8. Emulsion and sludge formation.

1.9.6 Formation damage during stimulation treatment:

Acid Treatments: During acid treatment following mechanisms are responsible for formation damage:

1. Fines migration.
2. Precipitation of Reaction by-products.
3. Sludge formation.
4. Emulsion formation.
5. Wettability alteration.
6. Water block.
7. Iron ion precipitation.

Formation damage during fracture treatment:
Fracture treatments are used to increase the productivity. But hydraulically fractured wells often show lower productivity increase than expected or inconsistent response from well to well. This is due to the formation damage caused by lack of proper care in the selection of

frac fluid, proppants and additives. Damage resulting from hydraulic fracturing takes 2 distinct forms: damage inside the fracture itself (proppant – pack damage) and damage normal to the fracture intruding into the reservoir (fracture – face damage).

Mechanisms that causes formation damage during hydrofracturing are:

1. Solid plugging
2. Clay swelling
3. Emulsion blocks
4. Water blocks
5. Rock wettability change

Formation damage during water injection and different EOR methods:

The different mechanisms which can affect the result of the water injection and different EOR methods by damaging the formation are as follows:

1. Solid invasion and fines migration
2. Clay swelling and Clay deflocculation
3. Formation dissolution
4. Skim oil entrainment
5. Biologically induced impairment
6. Sand influx
7. Chemical adsorption/wettability alterations
8. Formation of insoluble scales and emulsification
9. Precipitate formation

1.9.7 Remedial measures:

Remedial measures for various formation damages are given in the following table:

Damage mechanism	Remedial measures
Particle invasion	Matrix acidization, Perforation, Hydraulic fracturing
Hydration and swelling of clay minerals	Matrix acidization, Hydraulic fracturing, Clay stabilization
Mutual precipitation of soluble salts in the filtrate and formation water	Matrix acidization
Movement and plugging by clay	Matrix acidization ,Clay stabilization
Plugging by invading materials from the wellbore fluids	Matrix acidization
Emulsion and water blocks	Surfactant treatment, Matrix acidization
Relative permeability effects	Surfactant treatment
Precipitation of scales	Acidization
Plugged perforations due to improper perforating conditions	Acidization, Perforation
Slumping of unconsolidated sands	Sand consolidation, Frac and Pack
Water block	Surfactant treatment, Matrix acidization
Emulsion block	Surfactant treatment, Matrix acidization

Table 1 Remedial measures for formation damage
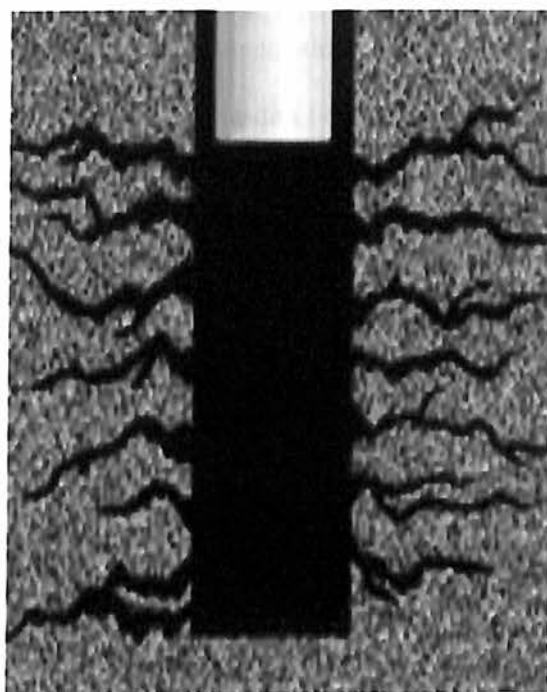
Well Stimulation

2. Matrix Stimulation

2.1 Introduction:

Matrix stimulation is a technique that is used to improve production from oil and gas wells and to improve injection into injection wells. Matrix stimulation is accomplished by injecting fluid (acid or solvent) to dissolve and/or disperse materials that impair well production in sandstones or to create new, unimpaired flow channels between a wellbore and reservoir in carbonate formations. In matrix stimulation, fluids are injected below the fracturing pressure of the formation.

Once it has been established that a well is producing below its potential, an assessment of the cause and location of the impairment must be made. Then the stimulation technique is determined. Selection of the stimulation technique is based on the productivity, lithology, operational limitations and various other considerations.

The treating fluid system is selected on the basis of field experience and laboratory testing and can be derived from an expert system.

The volume of each material pumped is based on an assessment of the amount of damage or the required depth of treatment and must address the potential inefficiency of the placement process. The location of the damage dictates the placement technique. Both mechanical methods using tools and fluid mechanical methods (like particulate suspensions and foams) can be used to ensure that the stimulation fluids contact the formation damage.

A field validated stimulation simulator should be used for the systematic engineering of matrix stimulation treatments. A numerical simulator can be a valuable tool for predicting damage removal and evaluating skin effect evolution, flow profile and wellhead and bottomhole pressures versus injection rate for the proposed pumping schedule. The simulator should take in to consideration both the chemistry and damage removal along with the placement strategy.

Materials should be monitored to ensure that they meet the specifications of the design, equipment must be maintained to perform properly, and personnel on site must understand and execute their assigned roles. Quality control testing and training should be documented as standard practices.

2.2 Identifying low productivity wells and stimulation candidates

To identify wells with low productivity relative to what they are capable of producing, the productivity index (PI), productivity index per net pay thickness
PI/h, production rate in barrels of oil per day (BOPD), production rate per reservoir porosity thickness product (BOPD/porosity-ft) or skin effect can be plotted for each location. Once the production potential of a well is established, it can be compared with the actual production. When the well is diagnosed as underperforming, the reason or reasons must be determined.

Once the mechanical reasons are eliminated as a potential cause of poor production, the remaining wells become stimulation candidates.

A method is used to estimate the theoretical reservoir flow. Comparison of the actual rate to the computed theoretical rate is made. The well is stimulated if the actual rate is less than 75% of the theoretical. Once the analysis has been computed, wells with low permeability or pressure can be identified. In these cases, matrix stimulation will not provide an economic improvement in performance, but fracture stimulation may be appropriate.

2.3 Impact of formation damage on productivity

A knowledge of the inflow relationship and Hawkin's equation is essential to understand the effects of near-wellbore formation damage on well production.

The steady-state equation for an oil well is:

$$Q = \frac{kh\,(p_e - p_{wf})}{141.2B\mu\,[\ln\,(r_e/r_w) + s]}$$

Where,

- k is the permeability in mD,
- h is the reservoir thickness in ft,
- p_e is the constant outer reservoir pressure in psi,
- p_{wf} is the bottomhole flowing pressure inpsi,
- B is the formation volume factor in RB/STB,
- μ is the viscosity in cp,
- r_e, r_w is the drainage and wellbore radius respectively in ft,

The total skin effect s is a dimensionless term used to account for the additional pressure drop in the wellbore area that results from formation damage and other factors (e.g., inadequate perforations, partial completion).

Skin effect values, determined from PTA, typically range from 0 to more than 100. Thus, for a well with total and damage skin effects equal to 100, a reduction to 10 can exhibit a six fold increase in productivity. A skin effect reduction from 100 to 0 leads to a 14-fold increase in productivity.

An estimate of the skin effect may be available from production system analysis, or the skin effect may have been determined directly by PTA. If the skin effect is greater than zero, there is potential benefit from matrix stimulation.
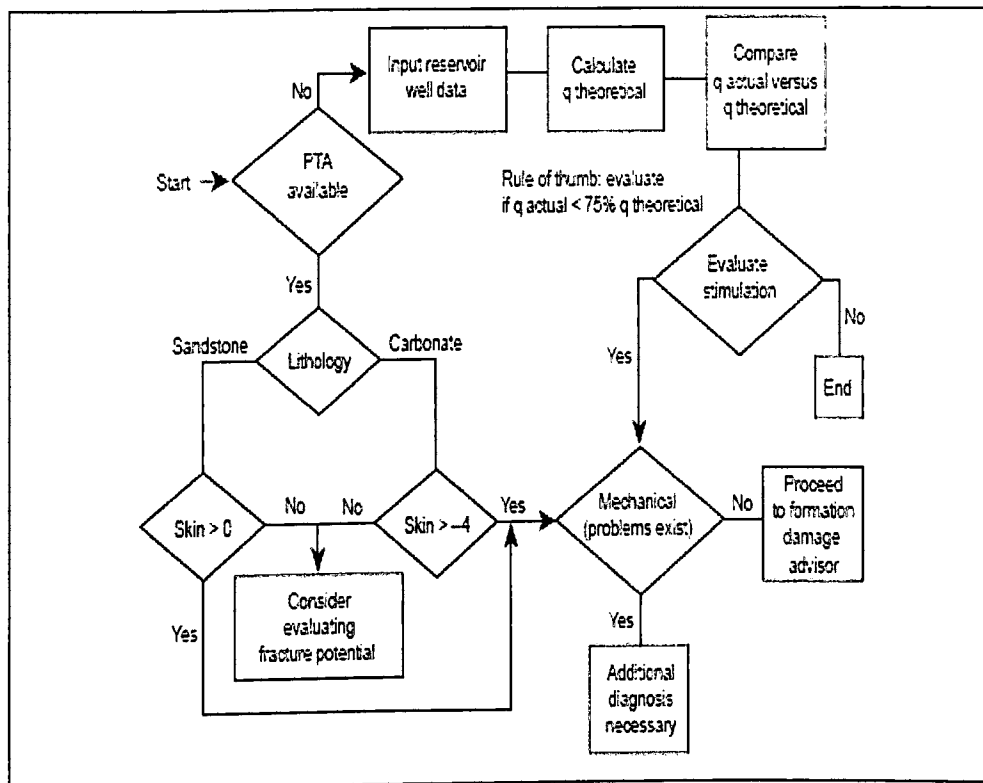
Fig.4 Impact of formation damage on productivity

2.4 Stimulation technique determination

If the productivity target can be reached with a skin effect of 10% of the original damage skin effect in sandstones and –2 to –3 in carbonates, matrix stimulation will be adequate and probably cost effective. In sandstone reservoirs the only stimulation alternative is hydraulic fracturing. In carbonate reservoirs (limestones or dolomites) acid fracturing can be a cost effective way to increase productivity.

A flow chart of identification of stimulation technique is given in the following figure.
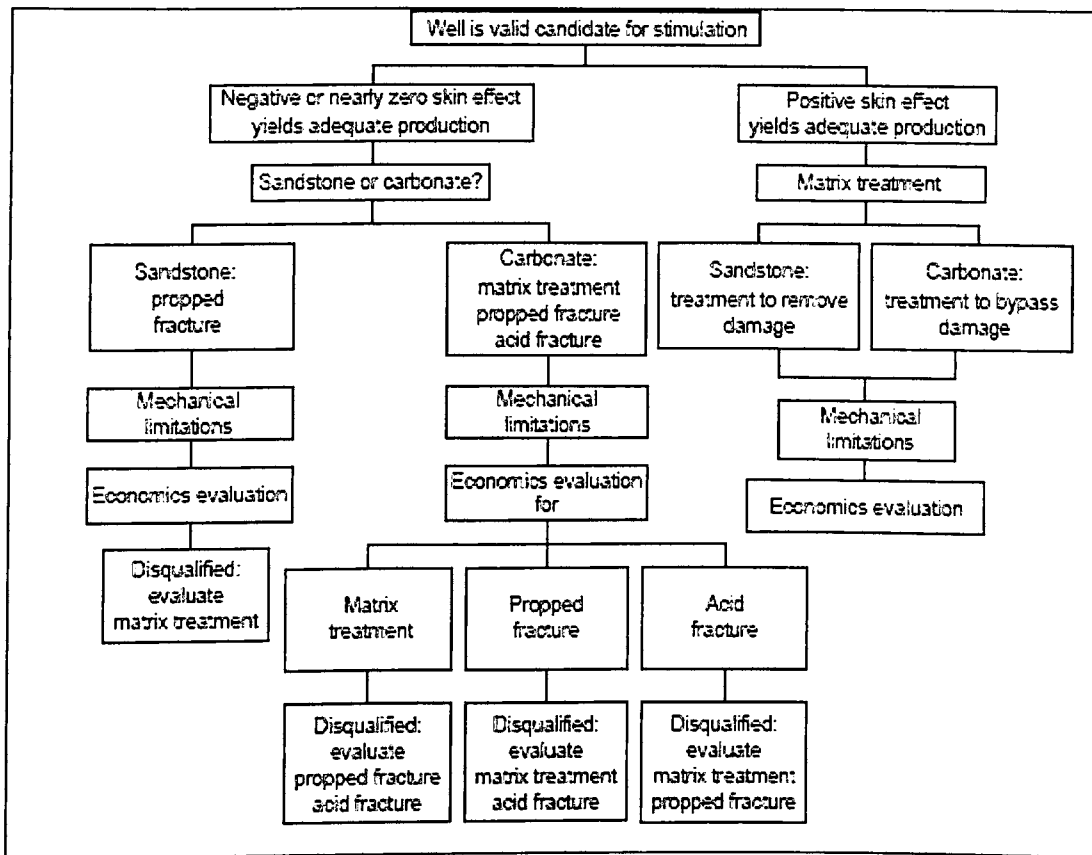
Fig.5 Identification of stimulation technique

2.5 Treatment design

Matrix stimulation techniques
Two types of non fracture treatments are used to improve production in oil and gas wells.
• Wellbore cleanup
Wellbore cleanup uses chemical and/or mechanical methods to clean the wellbore. Wellbore cleanup is commonly used to remove scale, paraffin, bacteria or other materials from the tubing, casing or gravel-pack screen. These treatments normally use acid or solvent systems that are placed in the wellbore area to soak. Key parameters in treatment design are the placement technique, chemical selection and soak time. Chemicals should be selected on the basis of their effectiveness at dissolving the suspected damage. In low-pressure wells, nitrogen (N2) is recommended to assist the removal of reacted treating fluid.

• Matrix stimulation
Matrix stimulation treatments injected below fracturing pressure down tubing, drillpipe or coiled tubing usually include a sequence of several fluids, referred to as stages. A minimal treatment consists of a preflush stage with a non damaging, nonreactive fluid to establish

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an injection rate, a stage of the main treating fluid and an overflush stage to clear the main treatment fluid out of the tubing and displace it into the near-wellbore area. In most treatments, other auxiliary stages are included to enhance the effectiveness of the treatment. The selection of chemicals for the stages and the design of the treating sequence (pumping schedule) are key parameters.

2.6 Treatment fluid selection

Multiple fluids (fluid systems), composed of base fluids and additives, are selected on the basis of lithology, damage mechanism and well condition.

2.7 Main treating fluid selection

The main treating fluid is selected to dissolve or disperse the principal damage in sandstone formations and to allow soluble products or solids to flow out of the well. In the case of carbonate formations, the goal is to bypass the damage with acid or dissolve the damage with solvents. The main treating chemicals fall into the following categories:
– Solvents to remove organic deposits (such as paraffin)
– Oxidizers to remove damage from polymers
– scale removers to remove sulfate or oxide scales
– Acids to remove carbonate and oxide scales break polymer residues or stimulate carbonate formations
– Hydrofluoric acid (HF) to remove aluminosilicate damage (primarily clays) from sandstone formations.

2.8 Acid stimulation

Acid stimulation is performed to remove or bypass a variety of damages. Acids are also used to stimulate the near-wellbore region of the reservoir. In carbonates, HCl or organic acids (formic or acetic) are used to etch conductive paths between the wellbore and the formation. In sandstones, mixtures of HCl and HF (mud acids) are used to remove drilling mud, formation fines, fines generated during drilling and perforating residue.

2.9 Fluid formulation for matrix acid stimulation

Formulating fluids for matrix acid stimulation includes selection of the main acid and identification of the need for preflushes and overflushes. Fluid selection depends on the damage type, lithology, mineralogy and type of well. It is also based on field and laboratory experience and can be derived from an expert system.

2.10 Fundamentals of acid-rock chemistry

Carbonate reservoirs:
HCl is used for carbonate acidizing because it readily dissolves calcite and dolomite.
The reaction of limestone (calcium carbonate, or $CaCO_3$) with HCl is

$CaCO_3 + 2HCl \rightarrow CaCl_2 + H_2O + CO_2$

For dolomite, the reaction becomes

$CaMg(CO_3)_2 + 4HCl \rightarrow CaCl_2 + MgCl_2 + 2H_2O + 2CO_2$

Acid reaction with carbonate reservoirs is governed by three mechanisms:
- Wormholing.
- compact dissolution.
- radial flow.

Each mode occurs under certain conditions. At low injection rates, compact dissolution occurs when the formation face is dissolved to enlarge the wellbore. If the flow rate is increased to where the Peclet number (a function of injection rate, acid concentration and diffusion rate) is approximately 1, then wormholing initiates. If the rate is increased significantly, radial flow dominates in a manner

similar to sandstones. Wormholing probably occurs in most treatments owing to the heterogeneous nature of carbonates; i.e., normally there are thief pores where wormholing initiates.

Wormholes formation in carbonates

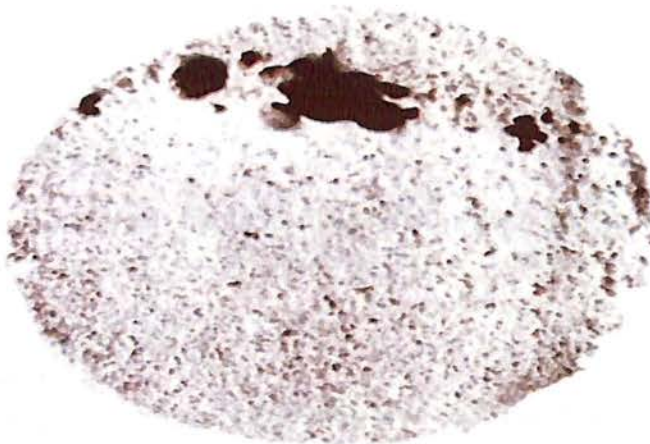
Fig.6 wormholes in carbonate rock

It is not known who first described the acid-etched pathway as a "wormhole," but this appellation is commonly accepted by those familiar with the complex etch pattern produced by acidizing carbonate cores in the laboratory. Here is a photograph of a metal casting of a wormhole created by forcing molten metal into a wormhole, allowing the metal to solidify

and then dissolving the remaining rock with HCl. The casting illustrates the complex morphology of the etch pattern. This is typical of many castings, which have been produced under a variety of experimental conditions. The chaotic nature of the pattern seemingly discourages any attempt to characterize its structure. However, it has been suggested that there is an underlying regularity that may be useful for modeling. A fractal is a self-similar geometric pattern. This implies that under increasing magnification the same pattern will continue to reappear. Thus, according to this notion the structure of a large wormhole is repeated with branches from the main trunk that are smaller replicas of the larger one. This replication is repeated as the magnification is ncreased until the pores of the native rock come into view. These do not resemble acid etch patterns because they were created by different processes. The discovery by Daccord and Lenormand that wormholes are fractals is a significant contribution.
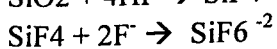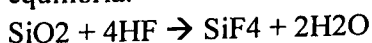
Initiation of wormholes

The fractal or self-similar, topology of a wormhole structure implies that the mechanism for the initiation of wormhole is a "local" phenomenon that occurs continuously along its bounding surfaces as well as at its tip. Thus, tiny wormholes may be initiated whenever live acid enters the pores of the virgin rock irrespective of the etch pattern already in existence. These pores are distributed in size and shape; therefore; the amount of acid flowing through each of the pores differs. The rate at which a given pore is enlarged by the acid depends, of course. On the amount of acid entering that pore and the fraction of the acid reacted at the walls of the pore before the acid exits and then enters other pores located downstream. Thus, even at the pore level, the processes that contribute to the creation of an etch pattern are complex, involving convection, diffusion and chemical reactions within each invaded pores.

Sandstone reservoirs

Mud acid mixtures of HF and HCl are used for sandstone acidizing.
The primary reaction of HF with quartz grains (pure silica) is expressed in the two following equilibria:
$SiO_2 + 4HF \rightarrow SiF_4 + 2H_2O$
$SiF_4 + 2F^- \rightarrow SiF_6^{-2}$
The intent of sandstone matrix acidizing is to dissolve clays and other damaging materials, leaving the sandstone matrix undisturbed.
For aluminosilicates (clays and feldspars), the primary reaction is
$M_zAl_xSi_yO(z/2 + 3x/2 + 2y) + 6(x + y)HF \rightarrow xAlF_6^{3-} + yH_2SiF_6 + (z/2 + 3x/2 + 2y)H_2O + (3x - z)H+ + zM^+$
where M is a metal atom (e.g., Na or K).
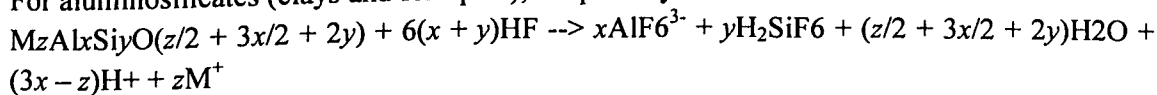
2.11 Acid and formation compatibility

— Iron hydroxide

Precipitation of iron (ferric, Fe^{3+}) hydroxide ($Fe(OH)_3$) can occur during sandstone and carbonate acidizing when the pH value is greater than 2.2. Ferrous iron (Fe^{2+}) is not a problem in sandstone acidizing because ferrous hydroxide does not precipitate until the pH value exceeds 7.7. Iron increases the tendency of oil to form rigid films and emulsions with acids. These problems can result in formation damage and facility upsets when producing wells after acidizing.

In addition, sludging can occur because of the coagulation of asphaltenes plugging pore throats. Both emulsions and sludging can be avoided by adding the appropriate chemical determined from laboratory testing. Preflushes of solvents or potassium or ammonium chloride with mutual solvents are used to separate the crude oil from the acidic fluids.

— Carbonates

Formulating acids for carbonates is relatively simple because the majority of the reaction products is simply calcium chloride, water and carbon dioxide, which do not undergo further reactions. However, there are numerous minerals (silt and clay) in most carbonates that are insoluble in HCl. The insoluble material normally flows back through large wormholes or fissures and is not a problem.

— Sandstones

The sensitivity of a sandstone formation to a matrix treatment fluid depends on the mineralogy of the formation, damage type, reaction products, temperature and permeability. Thus, sensitivity is related to chemical and mechanical problems in sandstones. Although sensitivity cannot be eliminated completely, the goal is to minimize it by selecting fluids with the greatest possible compatibility with the formation.

The solubility of the formation in HCl is normally considered to represent the carbonate content of the sandstone. Excessive carbonate can react with the HF to precipitate calcium fluoride, and spent HF can react to form calcium hexafluosilicate. Thus, in sandstone acidizing, an HCl (or organic acid) preflush is used ahead of the mud acid.

Secondary reactions can occur to form precipitates in the sandstone if precautions are not taken. Precipitates that are formed include fluosilicate(SiF_6^{-2}), calcium fluoride, aluminum salts like aluminum fluoride (AlF_3) and aluminum hydroxide ($Al(OH)_3$) and hydrated silica are formed.

2.12 Acid selection guidelines

A flow chart for acid selection guidelines is given in the following figure:
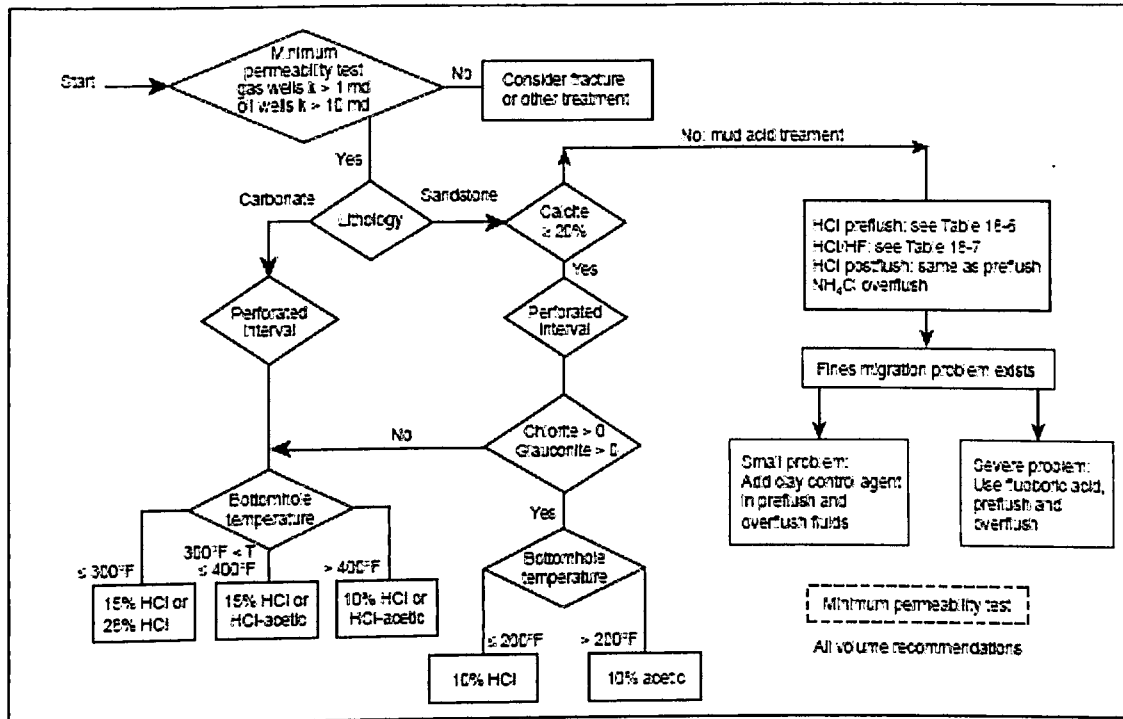
Fig.7 Acid selection guidelines

Carbonate reservoirs:

Temperature- at temperatures greater than 300°F [150°C], 28% HCl cannot be used because of excessive corrosion whereas 15% HCl can be used. Above 400°F, organic acid or fluids containing ethylenediaminetetraacetic acid (EDTA, a non-acid-reactive solvent) can be used.

Mineralogy—Calcite and dolomite react differently with acids. Acid formulation should be optimized to achieve the desired reaction and penetration characteristics in each formation.

Petrophysics—Acid penetration and the amount of damage depend on the type and distribution of porosity. Because much of the porosity (hydrocarbons in place) is located in the vugular or fissure network, it is essential to remove the damage and restore communication with the wellbore.

Sandstone reservoirs:

Temperature--The sensitivity of a sandstone formation increases with temperature because of the rapid spending of HCl and mud acid and generation of mobile fines in the spent acid;

however, the sensitivity resulting from precipitation reaction products decreases with temperature because of their increased solubility.

Mineralogy—Because of the large surface area of silts and clays, most mud acid reacts rapidly to generate a complex mixture of compounds. Acid penetration is highly dependent on mineralogy because of the large surface area of silts and clays.

Petrophysics—the sensitivity of a sandstone depends on the permeability of the formation. Because permeability is a function of pore size, low-permeability sandstones are more sensitive than high-permeability sandstones for a given mineralogy. Thus, the permeability must be considered in fluid selection.

2.13 Matrix acidizing design guidelines

1. Estimate safe injection pressures:
   a. determine present fracturing gradient
   b. determine present bottomhole fracturing pressure
   c. determine allowable safe injection pressure at both the wellbore and at the surface.
2. Estimate safe injection rate into the damage-free formation.
3. Estimate safe injection rate into the damaged formation.
4. Select stages required for fluid compatibility.
5. Calculate volume of each stage required:
   a. crude oil displacement
   b. formation brine displacement
   c. HCl stage or acetic acid stage
   d. mud acid stage
   e. overflush stage.
6. Select acid concentrations according to formation mineralogy.

Acid selection guidelines

The table depicts the acid selection guidelines for different mineralogy and permeability conditions of formation rock:

Table 18-5. Acid use guidelines for sandstone acidizing (McLeod, 1984).	
Condition or Mineralogy	**Acid Strength (blend)**
HCl solubility > 20%	HCl only
High permeability (>50 md)	
High quartz (>80%), low clay (<5%)	12% HCl–3% HF[1]
High feldspar (>20%)	13.5% HCl–1.5% HF[1]
High clay (>10%)	10% HCl–1% HF[2]
High iron/chlorite clay (>15%)	10% acetic acid–1% HF[3]
Low permeability (≤10 md)	
Clay (<10%)	6% HCl–1% HF
Clay (>10%)	6% HCl–0.5% HF
[1] Preflush with 15% HCl [2] Preflush with 10% HCl [3] Preflush with 10% acetic acid	

Table 2 Acid selection guidelines

2.14 Preflush fluid selection

The preflush has three important functions. A preflush of a nonreactive fluid is pumped initially to ensure that injection can occur at an acceptable rate and pressure. In some oil wells, it is advisable to inject a preflush formulated to remove oil from the near-wellbore region and leave the minerals and damage in a water-wet condition. When acidizing with mud acid, an acid (HCl or organic acid) preflush is used to remove calcium carbonate and iron carbonate or oxide from the near-wellbore region.

Table 18-6. Fluid selection guidelines for preflush fluids.			
Mineralogy	**Permeability**		
	>100 md	20 to 100 md	<20 md
<10% silt and <10% clay	15% HCl	10% HCl	7.5% HCl
>10% silt and >10% clay	10% HCl	7.5% HCl	5% HCl
>10% silt and <10% clay	10% HCl	7.5% HCl	5% HCl
<10% silt and >10% clay	10% HCl	7.5% HCl	5% HCl
Note: Selection guidelines for all temperatures			
For 4% to 6% chlorite/glauconite, use <20-md guidelines with 5% acetic acid			
For >6% to 8% chlorite/glauconite, do not use HCl, use 10% acetic acid preflush to mud acid plus 5% acetic acid			
For >8% chlorite/glauconite, do not use HCl; use 10% acetic acid and organic mud acid			
For <2% zeolite, use 5% acetic acid in all fluids containing HCl and preflush with 10% acetic acid			
For >2% to 5% zeolite, do not use HCl preflush; use 10% acetic acid preflush and overflush to mud acid containing 10% acetic acid			
For >5% zeolite, do not use HCl in any system; use 10% acetic acid preflush and overflush to organic acid prepared from 10% acetic and HF			

Table 3 Preflush fluid selection

2.15 Main acid volume and concentration

For the most successful mud acid treatment, more than 125 gal/ft of mud acid is required. Less may be used where only shallow damage exists around new perforations (e.g., 25 to 75 gal/ft is used to remove mud damage or in spearhead
treatment as an aid to perforation breakdown prior to hydraulic fracturing).
Regular mud acid (12% HCl–3% HF) is the normal concentration to use to remove damage in clean quartzose sands. If the combined percentage of clay and feldspar is more than 30%, 1.5% HF or less should be used.

Table 18-7. Fluid selection guidelines for mud acid fluids.			
Mineralogy	Permeability		
	>100 md	20 to 100 md	<20 md
<10% silt and <10% clay	12% HCl–3% HF	8% HCl–2% HF	6% HCl–1.5% HF
>10% silt and >10% clay	13.5% HCl–1.5% HF	9% HCl–1% HF	4.5% HCl–0.5% HF
>10% silt and <10% clay	12% HCl–2% HF	9% HCl–1.5% HF	6% HCl–1% HF
<10% silt and >10% clay	12% HCl–2% HF	9% HCl–1.5% HF	6% HCl–1% HF
Notes: Selection guidelines for all temperatures			
For 4% to 6% chlorite/glauconite, use <20 md guidelines with 5% acetic acid.			
For >6% to 8% chlorite/glauconite, use 10% acetic acid preflush to mud acid plus 5% acetic acid.			
For >8% chlorite/glauconite, use 10% acetic acid and organic mud acid.			
For <2% zeolite, use 5% acetic acid in all fluids containing HCl			
For >2% to 5% zeolite, use 10% acetic acid preflush and overflush to mud acid containing 10% acetic acid.			
For >5% zeolite, use 10% acetic acid preflush and overflush to 10% citric acid/HF.			

Table 4 fluid selection guidelines for mud acid fluids

2.16 Postflush fluid selection

A postflush is almost always used to remove the reactive (and corrosive) fluid from the tubing and maximize the contact of main fluid with the near wellbore area. The decision to inject a postflush fluid depends on the type of stimulation. It has several purposes like to displace nonreacted mud acid into the formation, to displace mud acid reaction products away from the wellbore and to remove oil-wet relative permeability problems caused by some corrosion inhibitors.

2.17 Diverting agent selection

Nonuniform damage and permeability heterogeneity in targeted zones because treating fluids to preferentially enter thief zones. Diverters are used to help control the distribution of acid in the wellbore. The four general types are bridging agents (60 mm), particulates (4 to 60 mm), viscous solutions (gels) and foams. Bridging agents are relatively large particles that are used to bridge at the face of fissures in carbonate formations; particulates are smaller particles that are used in sandstones. Viscosifiers should be stable enough to provide significant resistance

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to flow, but they must degrade fast and completely so that they do not impede production. Viscosifiers are normally used in carbonate formations. Foams are made by adding a foaming surfactant to the acid or brine and mixing it with N2.

2.18 Matrix treatment fluid additives

Additives are mixed with the treating fluid to modify a property (e.g., corrosion, precipitation, emulsification, sludging, scaling, fines migration, clay swelling tendency, surface tension, flow per layer, friction pressure).
Additive types are as follows:

Acid corrosion inhibitors—Different corrosion inhibitors are required for all inorganic and organic acids. Partially spent HF may still be highly corrosive.

Iron stabilizers—Additives to control iron are required in all acid treatments. They can be grouped in three categories: buffers keep the pH value less than 2.2, chelating or complexing agents bond to the iron and suppress other reactions and are used to prevent precipitation and sludging; and reducing agents prevent oxidation of the iron from ferrous to ferric.

Surfactants—Surfactants are used to reduce oil/water surface tension, ensure water wetness, prevent sludge and stabilize foams.

Mutual solvents—Mutual solvents are used to ensure that the formation remains water-wet and to lower surface/interfacial tension.

Diverters—are used to bridge in perforations and/or fissures in carbonate formations and injection wells.

Scale inhibitors—Scale inhibitors are materials that suppress the precipitation of inorganic scales from produced fluids.

Clay stabilizers—decrease clay migration. They are temporarily effective at low concentrations.

2.19 Pumping schedule generation and stimulation

Treatment sequences:
1. Tubing clean up (pickling)
2. Flow back
3. Preflush

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4. Main acid
5. Overflush
6. Flow back

Note: If diverting stage is required, it is to be introduced sequentially in the main acid treatment.

The pumping schedule includes the treating fluid and diverter sequence and the injection rate of each stage.

Table 18-8. Acid treatment sequence and fluid options.	
Stage	Fluid System
1. Preflush	Brine
	Hydrocarbons
	HCl
2. Main fluid	HCl-HF formulation
3. Overflush	HCl or NH₄Cl
4. Diverter	Foam or slug OSR
5. Repeat stages 1–4 as necessary with 1–3 as the last fluid sequence	
6. Fluoboric acid	With diverter solvent for OSR or foam-weakening agent (mutual solvent)
7. Fluoboric acid diverter	Fluoboric acid-based fluid system, either foamed or slug OSR
8. Fluoboric acid	Fluid left at the perforations

Table 5 acid treatment sequence and fluid options

2.20 Tubing pickle (cleaning)

The purpose of the pickling process is to
- remove rust, iron oxides and scale
- dissolve oily films and pipe dope that could plug the downhole equipment and perforations
- limit the amount of iron that gets into the formation and contacts the crude oil.

2.21 Sandstone acid job stages

Stage Number	Stage	Reason for Stage	Information Source	Stage Composition	Stage Volume
span — **Table 18-9. Typical stage sequence for a sandstone acidizing treatment.**					
1	Crude oil displacement	To prevent oil sludge formation by the acid	Acid–crude oil sludge test	Aromatic solvent	To achieve 3-ft radial displacement
2	Formation water displacement	To prevent scale deposition	HCO_3 and SO_4 contents from formation water analysis	Ammonium chloride (NH_4Cl) at 3%–8% depending on the salinity of the formation water	To achieve 3-ft radial displacement
3	Acetic acid	Iron compounds in formation (pyrite, siderite, hematite), chlorite, clay, zeolites	X-ray-diffraction (XRD) analysis	3%–10% acetic acid	CaCO₃ (%) — Volume (gal/ft): 0–5 → 25; 5–10 → 50; 10–15 → 75; 15–20 → 100
4	Hydrochloric acid	$CaCO_3$ or other HCl-soluble minerals	HCl solubility test and/or XRD analysis	According to core mineralogy: 3%–15% HCl	Calculated on the basis of HCl solubility and porosity (see Table 18-5) or this schedule: HCl Solubility of HF (%) — Stage Volume (gal/ft): <5 → 50; 5–10 → 100; 10–20 → 200
5	Hydrofluoric acid (not used for carbonates and sandstones where HCl solubility > 20%)	To remove clay, other formation fines and mud damage	XRD analysis, SEM analysis, HCl:HF solubilities	According to formation mineralogy: 3%–13.5% HCl with 0.5%–3% HF	75–100 gal/ft
6	Overflush	To spend acid and flush spent acid away from the near-wellbore area	Always used	3%–8% NH₄Cl or 3%–5% HCl in all wells followed by nitrogen (gas wells), kerosene (oil wells) or 5% HCl (water injection wells)	One to two volumes of the HCl:HF volume or to achieve 5-ft radial displacement
7	Diversion	To improve injection throughout the interval	Used as required for heterogeneous formation permeability	OSR for oil or low gas/oil ratio wells, foam for either oil or gas wells and water-soluble resins for water injector wells	

Table 6 sandstone acid job stages

2.22 Placement strategy

Placement strategy is an important step in the design of a matrix treatment. The goal is how to obtain uniform penetration of the treating fluid throughout the entire section and/or into

each natural fracture system. If complete zone coverage is not achieved, full production potential cannot be realized.

The importance of the placement strategy is magnified in a horizontal well because of the long interval. The placement technique is based on the information available for the well. If a spinner survey indicates that a thief zone exists in the center of the horizontal length, the coiled tubing can be run to that depth, followed by injection of a diverter slug.

Diversion must be achieved to ensure that the treating fluid is continuously removing damage rather than simply being injected into a thief zone.

Bullheading acid with a diverter normally results in poor coverage beyond 200 to 300 ft. Apparently the acid rapidly creates a thief zone at the entrance to the zone, and conventional chemical diversion techniques are ineffective. If coiled tubing is used, a diverter can be placed across a known thief zone followed by running the coiled tubing to total depth. Acid is then pumped as the coiled tubing is withdrawn, and a diverter slug is injected every 100–200 ft as required. The result is uniform penetration over the damaged sections with a small amount of acid injection into the thief zone located at the heel.

The key to successful matrix acidizing in carbonate reservoirs is not the amount of acid injected but how it is injected. This is also true for sandstone reservoirs. Coiled tubing placement in combination with foam diversion in sandstones or carbonates appears to be an improved technique.

2.23 Treatment Execution

The execution (pumping operation) must be performed as specified by the treatment schedule or operator on location. During this process, QC and data collection are important. The operational objective is defined by the design.

Quality control:

QC is the process of ensuring that the materials and equipment meet specifications and are delivered in proper condition to the wellsite.

Properly trained personnel are the key to success. The wellsite personnel must understand the fundamentals of the stimulation techniques that will be used and must know how to use the equipment, software and techniques. Two keys to effective QC are communication and documentation. Suppliers and vendors should ensure that materials shipped to the wellsite meet specifications. Testing should be sufficient to ensure that materials will perform their required functions in the field. Calibration of all measuring devices, such as transducers and flowmeters, should be a regular part of maintenance procedures.

For stimulation operations, useful QC measures include
- On-site titration of acids to verify concentration
- Regular QC testing of each batch or lot of corrosion inhibitors by the service company
- Verification that surface-active agents are supplied in the specified concentration
- On-site testing of gel viscosity for diverters (carbonates)
- Regular testing of particle size and solubility of particulate diverters

- Sampling of fluids pumped during stimulation treatments, with the samples retained until the treatment has been evaluated.

Data collection:

Careful recording of events during the treatment should be made, including records of unusual observations by operations personnel. The basic information available from stimulation treatment minimally consists of a record of pressure and rate and a log of operations prepared by operations personnel. The modern approach is to provide continuous digital monitoring of the surface rate and pressure with either an on-site computer or digital data logger.

Memory gauges can also be run on treating strings to record the bottomhole temperature and pressure during treatment. They are retrieved after the treatment and analyzed directly. Surface-readout bottomhole pressure recording devices are also available. In addition, where coiled tubing is run, sensor packages to monitor pressure and temperature are used to determine bottomhole treating pressure for calculation of the skin effect.

2.24 Treatment evaluation

Pretreatment evaluation

A step-rate test can be performed prior to the stimulation treatment to quantify reservoir pressure, permeability and skin effect. The benefit to the operator is improved real-time evaluation. The permeability and reservoir pressure determined from the step rate test should be used in the subsequent real-time evaluation.

Real time evaluation

Advanced programs calculate skin effect evolution in real time, taking into account transient effects. The reservoir pressure response during pumping is computed assuming zero constant skin effect. One value of skin effect is provided, combining the effects of damage, completion and diverters. Using these tools, a more quantitative assessment of each component of the stimulation design can be made.

Post treatment evaluation

The evaluation of stimulation effectiveness is a process similar to well performance evaluation. In this section, the process is applied to returning wells to production following stimulation.

Wells should be subjected to pressure buildup and PTA following a stimulation treatment. These data are the basis for a quantitative assessment of the well and reservoir characteristics. Comparison of these results to pretreatment buildups can provide the best assessment of the success of the stimulation treatment.

In addition to examining oil production response, changes in the total fluid production (oil, water and gas) in reservoir volumes, gas/oil ratio and water/oil ratio must be reviewed. Well productivity must also be examined.

3. HYPOTHETICAL CASE STUDY

A case study for designing of acid stimulation treatment is given here under:

Well completion

Casing	Depth (m)	Size (inch)
Surface	300	13 $^3/_8$
Intermediate	1500	9 $^5/_8$
Production	2500	5 $^1/_2$
Production tubing	2480	2 $^7/_8$
Perforation interval	2508 – 15m	7 m

Table 7 casing interval

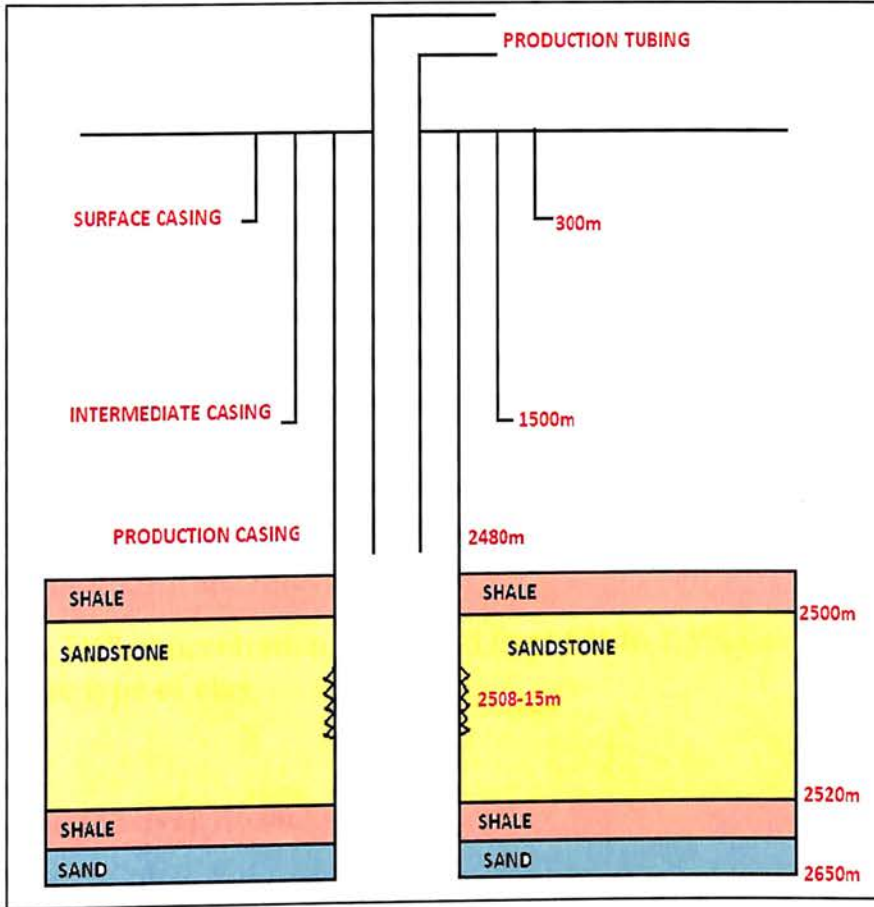The well schematic is given below

Fig. 8 well schematic

Reservoir data

Temperature: 80°C

Pressure   : 240 kg/cm^2

Depth   : 2500 – 2520m

Porosity   : 12%

Permeability: 50mD

Mineralogy : 80% quartz (SiO_2), 4% clay (kaolinite and chlorite), 15% feldspar,

         1% metallic oxides (Al_2O_3, K_2O, Na_2O, CaO)

Frac gradient: 0.7 psi/ft

Frac pressure: 5740 psi

Design of Stimulation fluids for matrix acidization:

Acid type: mud acid (HCl + HF) as it is a sandstone formation

Selection of preflush:

Preflush: 7.5% HCl with 2% NH_4Cl

(With reference to table on fluid selection guidelines for preflush fluids depending on permeability and mineralogy)

Selection of main acid:

Main Acid: 7.5% HCl – 1.5% HF at 125 gal/ft

(with reference to table on fluid selection guidelines for main acid depending on the permeability and mineralogy)

NOTE: HCl concentration is reduced from 9% to 7.5% due to presence of kaolinite type of clay

Selection of over flush: .

7.5% HCl with normal additives and mutual solvent (EGMBE). It should be at least 200 gal/ft of the perforations to ensure the displacement of all the acids to the formation and addressing any wettability issue.

Additives:

1) Acid corrosion inhibitors (0.5-1%)
2) Iron stabilizers (0.5%)
3) Surfactants (0.2 – 1%)
4) Diverters (benzoic acid, rock salt, OSRs)
5) Clay stabilizers
6) EDTA (0.5%)

Final formulation:

Preflush : 2% NH_4Cl + 7.5% HCl + 0.5-1.0% ACI (Acid corrosion inhibitor)+ 0.5% surfactant + 0.5% EDTA.

Main Acid : 7.5% HCl + 1% HF + 0.5-1.0% ACI (Acid corrosion inhibitor)+ 0.5% surfactant + 0.5% EDTA.

Overflush : 7.5% HCl + 0.5-1.0% ACI (Acid corrosion inhibitor) + 5% EGMBE + 0.5% surfactant + 0.5% EDTA.

Injection Rate:

Should be maintained to attain the maximum pressure which should be lesser than 80% of the fracture pressure, i.e., 5 – 8 barrels/min subject to maximum pressure of 2000 psi

Treatment Sequence:

Stage	Formulation	Volume(m^3)	Inj. Rate
1	Tubing pickling	7.5	5-8 bpm (subject to max surface pr of 2000 psi)
2	Flow back		
3	Pre flush	15	
4	Main acid	30	
5	Over flush	15	
6	Flow back		

Table 8 Acid treatment sequence

Assuming the well to be badly damaged with partial completion we take the initial value of skin damage to be 100.

CALCULATIONS

R_e = 912.33 ft

B_o = 1.32 scf/stb

μ = 1.3 cp

h = 65.6 ft

x_f = 0.5 ft (assumption)

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$w_f = 2.5 \times 10^{-3}$ ft

FCD = 15 (assumption)

$R_w = 1.35$ ft (taking wellbore diameter to be 16")

S = 100 (initial skin value, before the start of treatment)

$$J = \frac{qsc}{pe - pwf} = \frac{kh}{141.2 \mu Bo \left[ln\left(\frac{re}{rw}\right) - \frac{3}{4} + sd \right]}$$

On calculating we obtain the value of productivity to be

J = 0.128 bbl/psi.

After applying matrix acidization techniques, we again calculate the value of production rate.
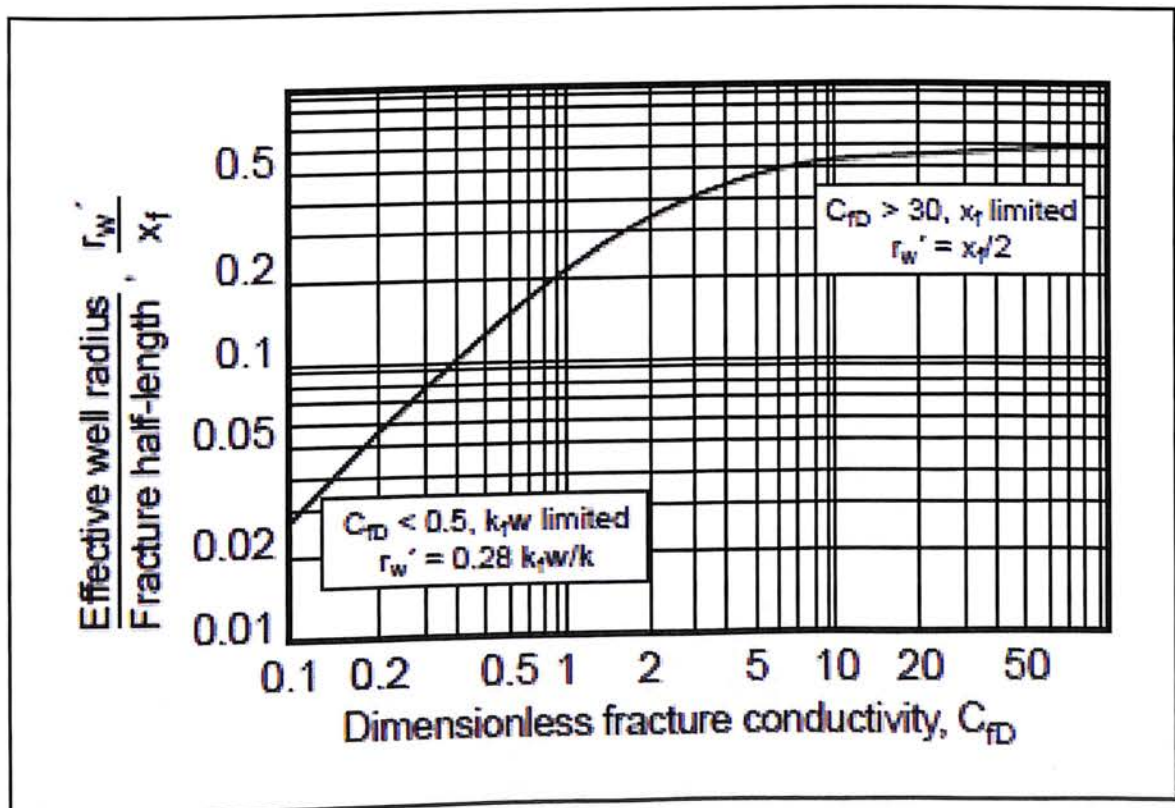

Fig.9 Prat's correlation chart

Since FCD is assumed to be 15, corresponding value of r_w'/x_f from the graph is estimated to be 0.45.

Therefore:

$r_w' = 0.225$ ft.

we know the relation:

$$r_w' = r_w e^{-S}$$

So we obtain the value of S to be 1.8.

And the consecutive production rate is

J = 1.789 bbl/psi

Hence the folds of increase in productivity are 7.1%.

Thus we saw a **14 folds** increase in production rate on introduction of acid treatment methods.

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